CHAPTER 8: LIFE-CYCLE COST AND PAYBACK PERIOD ANALYSES

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CHAPTER 8: LIFE-CYCLE COST AND PAYBACK PERIOD ANALYSES

8.1 INTRODUCTION

This chapter of the TSD presents the Department's life-cycle cost (LCC) and payback period (PBP) analyses. It describes the method for analyzing the economic impacts of possible standards on individual consumers. The effect of standards on individual consumers includes a change in operating expense (usually decreased) and a change in purchase price (usually increased). The LCC analysis produces two basic outputs to describe the effect of standards on individual consumers:

- Life-cycle cost is the total (discounted) cost that a consumer pays over the lifetime of the equipment, including purchase price and operating expenses.

- Payback period measures the amount of time it takes consumers to recover the assumed higher purchase expense of more energy-efficient equipment through lower operating costs.

This chapter presents inputs and results for the LCC analysis, as well as key variables, current assumptions, and calculations. The Department performed the calculations discussed here in a series of Microsoft Excel® spreadsheets, which are accessible over the Internet. Section 8.7 of this document contains details and instructions for using the spreadsheets. A complete set of results is presented in Appendix 8A.

8.1.1 General Approach for LCC

Recognizing that each transformer customer is unique, the Department calculated the LCC and PBP for a representative sample (i.e., a distribution) of individual customers. In this manner, the Department's analysis explicitly recognizes that there is both uncertainty and variability in its inputs. The Department used Monte Carlo simulations to model the distributions of inputs.

The Monte Carlo process statistically captures input variability and distribution without testing all possible input combinations. The results are expressed as the number of transformers experiencing economic impacts of varying magnitudes. The Department developed the LCC model using Excel® spreadsheets combined with Crystal Ball®, a commercially available add-in program. A detailed explanation of the Monte Carlo simulation process and the use of probability distributions is contained in Appendix 8B.

The LCC results are displayed as distributions of impacts compared to the baseline conditions. The Department presents tabular results at the end of this chapter; they are based on 10,000 samples per Monte Carlo simulation run. In addition, Appendix 8A consists of graphic displays illustrating the following analysis results for each standard level of each design line:

- a cumulative probability distribution showing the percentage of transformers that would have a net savings due to standards, and

- a frequency chart depicting variation in LCC for each efficiency level considered in the analysis.

The Department developed two approaches for the LCC calculations: one for liquid-immersed transformers and one for dry-type transformers. Because the large majority of liquid-immersed transformer owners are utilities, the liquid-immersed LCC calculations use utility marginal costs and distribution markups that do not include a wholesaler and contractor. Meanwhile, because a majority of dry-type transformer owners are commercial and industrial businesses, the Department used the monthly marginal electricity costs and complete distribution markups for the dry-type transformer LCC calculation. For simplicity, the Department used only one type of LCC calculation for each design line of transformer based on the majority owner of that category.

8.1.2 The Baseline Scenario

In developing appliance standards, the Department has traditionally used an existing standard level as a baseline from which it calculates the impact of any candidate standard level. Because distribution transformers are not currently subject to a national energy-efficiency standard, the Department developed an alternative approach to determine an appropriate baseline against which to compare various candidate standard levels. That alternative approach focuses on the mix of selection criteria customers are known to employ when purchasing transformers. Those criteria include first costs, as well as what is known in the transformer industry as total owning cost (TOC), used by some customers as an alternative criterion to first costs. The TOC method combines first costs with the cost of losses. Purchasers of distribution transformers, especially in the utility sector, have long used the TOC method to determine which transformers to purchase.[1, 2] To establish the LCC baseline scenario, the Department developed a process that uses distributions of efficiencies and an estimated percent of transformers currently being purchased using the TOC method. That scenario represents the range of transformer costs and efficiencies that transformer purchasers would likely experience without national energy-efficiency standards in place.

8.1.3 Total Owning Cost

The utility industry developed TOC evaluation as an easy-to-use tool to reflect the unique financial environment faced by each transformer purchaser. To express this variation in such factors as the cost of electric energy and capacity and financing costs, the utility industry developed a range of evaluation factors, called A and B values, in their calculations. A and B are the equivalent first costs of the no-load and load losses (in $/watt), respectively. No-load losses refer to the core losses that are roughly constant once the transformer is energized; load losses are the coil losses that vary roughly as the square of the load on the transformer.

The TOC transformer purchasers (i.e., those using the TOC method to determine which units to buy) assign an economic value to transformer losses: A and B parameters. Then they add these costs to the first cost of acquiring the transformer, to derive TOC. The equation for calculating transformer TOC is:

$$TOC = FC + (A * NLL) + (B * LL) \quad \textbf{Eq. 8.1}$$

where:

FC = first cost of acquiring the transformer,
A = the no-load loss valuation parameter,
NLL = the no-load loss at nameplate load,
B = the load loss valuation parameter, and
LL = the load loss at nameplate load.

8.2 LIFE-CYCLE COST METHOD

8.2.1 Definition

The basis for both the LCC analysis and the spreadsheet model is the LCC equation. The LCC equation reflects both the first costs of a transformer and the present value of the operating costs over the service life of the transformer.

The LCC equation is:

$$LCC = FC + SUM_{n=1,Lifetime} [OC_n/(1+Drate)^n] \quad \textbf{Eq. 8.2}$$

where:

FC = the first cost,
SUM = the sum over the service life,
n = the index for the year of operation,
$Lifetime$ = the service life of the transformer,
OC_n = the operating cost in year n, and
$Drate$ = the discount rate applied to the calculation.

The first cost includes the purchase price and installation cost of the transformer, while the operating cost includes the value of the losses and maintenance costs. Throughout the LCC analysis, DOE expresses dollar units in 2001 values.

8.2.2 LCC Spreadsheet Key Steps

While the LCC is a simple equation, the Department's LCC spreadsheet model takes into account the dynamic nature of a variety of inputs over the service life of a transformer. A simplified flowchart (Figure 8.2.1) illustrates the key steps implemented in the LCC spreadsheet: the main inputs, the key computational steps, and the important outputs.

Sections 8.2.2.1 through 8.2.2.11 describe, in step-by-step fashion, the computational flow of the LCC model as shown in the flowchart. Following this explanation of the analytical steps in the model, the Department presents the specific inputs that it developed and then used in the LCC model for this rulemaking. Next, DOE presents the results of the LCC model runs for the various design lines. Finally, the Department presents the key sensitivities to those results.

The LCC process is a means of determining the financial impact resulting from the imposition of energy-efficiency standards for distribution transformers. Several types of information are necessary for this calculation: the first costs of transformers with and without standards, the operating costs of the transformers with and without standards, the year the standard is to become effective, and the lifetime of transformers. For ease of comparison, DOE presents all costs in present values, which requires discount rates. The Department's methods for determining these inputs are explained in more detail in the LCC Inputs, section 8.3.

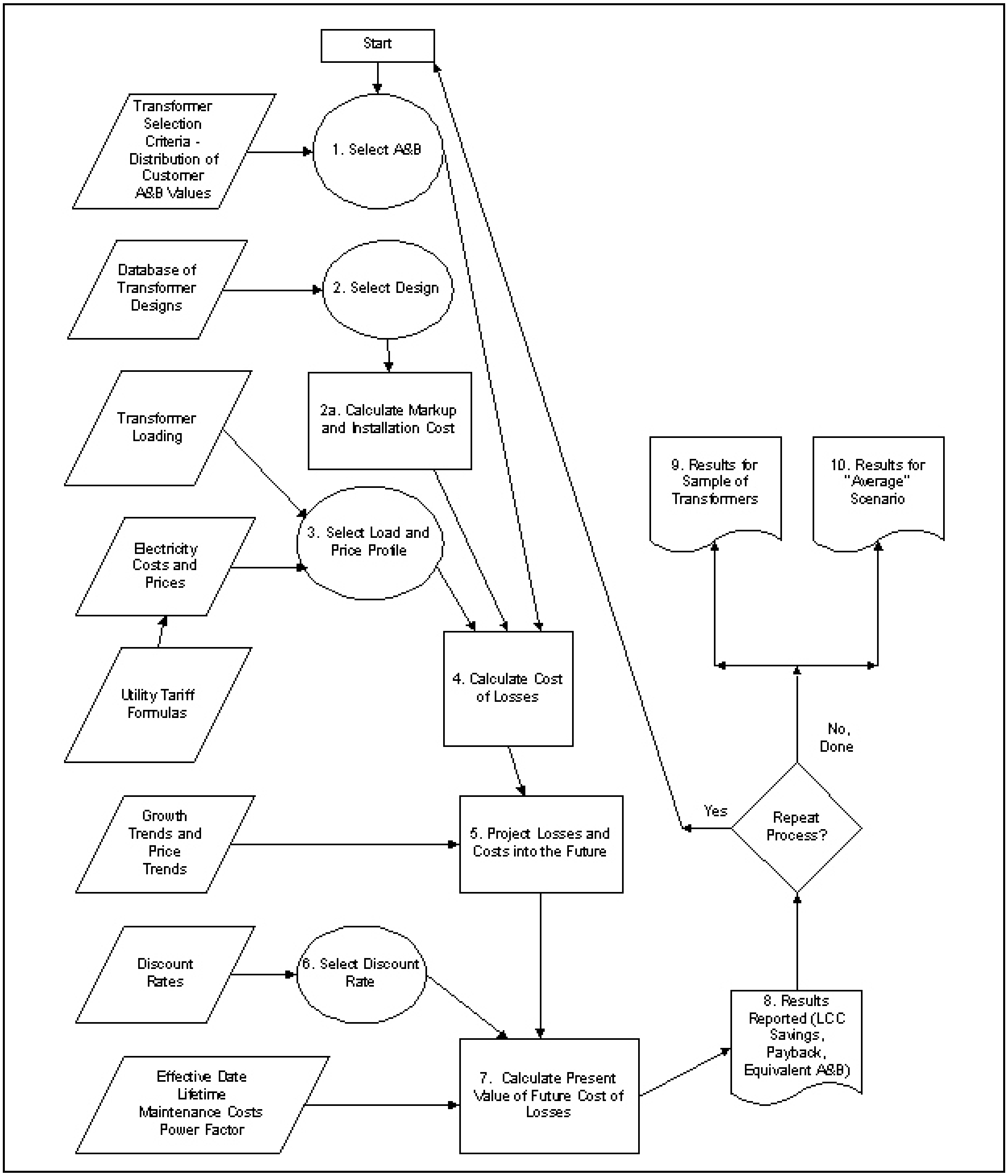

Figure 8.2.1 Transformer LCC Spreadsheet Model Flowchart

8.2.2.1 Step #1: Select A & B

Step#1: Select Customer Choice A and B parameters from the choices on the "A & B Dist" worksheet. The purpose of this step is to establish, for each spreadsheet analysis, the current purchasing decision environment. For liquid-immersed transformers, based on National Electrical Manufacturers Association (NEMA) comments, the Department assumed that 50 percent are purchased based on lowest first cost and 50 percent are purchased using TOC evaluation.[3]

Commercial and industrial (C&I) entities can also apply an A- and B-based evaluation process for dry-type transformer purchase evaluation. While the analytic process for determining A and B values used by C&I purchasers is different from that used by electric utilities, the fundamental meanings of A and B are the same for both groups of transformer purchasers.

The LCC spreadsheet simulates different transformer purchase evaluation scenarios with three different A and B distributions. All liquid-immersed transformer design lines use a common set of scenarios and all dry-type design lines use a different, but also common, set of scenarios. The specific inputs used in these three scenarios are shown in section 8.3 of this TSD, as well as in the "A & B Dist" worksheet of the LCC spreadsheets themselves. These scenarios can be selected using the “Customer Decision As & Bs" pull-down menu on the “Summary” worksheet. Step #2 below explains the application of these A & B distributions when actual transformer designs are selected.

8.2.2.2 Step #2: Select Designs that Meet a Chosen Candidate Standard Level

Step #2: Select designs and a candidate standard level. The purpose of this step is to select a candidate standard level and its associated transformer designs to evaluate with the LCC spreadsheet. The Department used NEMA’s TP 1-2002[1] as the first possible standard level to evaluate, and developed four additional standard levels based on information obtained from the engineering analysis. The engineering analysis yielded a cost-efficiency relationship in the form of manufacturer selling prices, no-load losses, and load losses for a wide range of realistic transformer designs. This set of data provides the LCC model with a distribution of transformer design choices. (See the “Design Table” worksheet, a condensed version of the engineering analysis output.) The manufacturer selling prices are in column C. After the user chooses a candidate standard level, the spreadsheet selects from its database of designs the subset of designs that satisfy the selected candidate standard level and another set of designs that satisfy the baseline scenario.

In addition to the economic value of losses, other factors may affect design selection. The Department accounted for such factors by including a random cost factor that is added to the transformer’s first costs. This factor is intended to capture the range of typical real world cost variation in the first cost of the transformer. The Department modeled this random cost factor as a uniformly distributed random number that can either raise or lower the first cost of the transformer by up to 15 percent. The spreadsheet selects the transformer design that has the lowest TOC (including the random cost factor) for the customer. For each iteration cycle, a design is chosen based on A and B distributions from step #1.

Step #2a: Calculate Markup and Installation Costs. For liquid-immersed transformers, which are typically purchased directly by the utilities from manufacturers, DOE considered the manufacturer selling price to be the transformer cost. Installation costs are added separately. For dry-type transformers, the distribution channel includes various intermediaries who add their own costs to the manufacturer selling price. These costs include a manufacturer markup, distribution markup, contractor markup, installation costs, and sales tax. For both liquid-immersed and dry-type transformers, DOE applied a nationally weighted sales tax to the cost of the transformer.

Key inputs for this step include Transformer Cost Markup and Installation Costs. The Department presents its specific values for these inputs in Chapter 7.

8.2.2.3 Step #3: Load and Price Profile

Step #3: The spreadsheet model dynamically selects a sample transformer load profile from the Department's choices of load profiles. This step estimates customer demand and usage both with and without transformer losses. The LCC calculation for each transformer uses monthly demand and root mean square (RMS) usage estimates to calculate customer bills for baseline and standards scenarios in the "'Baseline LCC" and "Standard Option LCC" worksheets, respectively. The Department estimated monthly energy data using a statistical hourly load simulation model (Chapter 6). The load simulation model provides hourly loads based on an estimate of the customer load factor and an estimate of the customer load correlation with the utility system load. The model calculated transformer losses from the resulting customer usage, demand, and RMS usage estimates. Those load profiles appear on the "Load & Price Parameters" worksheet of the LCC spreadsheet for liquid-immersed transformers and on the "Demand and Usage" worksheet of the LCC spreadsheet for dry-type transformers.

For the cost of electricity, the Department used the marginal cost of electricity for liquid-immersed transformers; for dry-type transformers, it developed a method to calculate customer monthly bills. For both transformer types, the Department calculated the total cost of electricity both with and without transformer losses and took the difference to calculate the incremental electricity costs. Section 8.3.5 provides a detailed discussion of the electricity price analysis.

8.2.2.4 Step #4: Calculate Cost of Losses

Step #4: The spreadsheet model calculates the costs of losses by combining the incremental impacts of no-load and load losses with the loss coefficients of the design, the monthly customer load characteristics (demand and usage), and the cost of electricity. In this step, the spreadsheet combines the no-load losses, load losses, and electricity price information for each transformer in the baseline scenario and in the candidate standards scenario. Subsequent steps extend these costs of losses into the future and then convert them back to present values.

8.2.2.5 Step #5: Project Losses and Costs into the Future

Step #5: The spreadsheet model projects losses and costs into the future, based on load growth assumptions and a forecast of future changes in electricity price. Spreadsheet users can select different load growth and future electricity price scenarios or use the medium assumptions of 1 percent load growth and DOE's Energy Information Administration (EIA) reference scenarios. The model applies the selected options for load growth and price trends to the current cost of losses that were calculated in Step #4. Step #5 results in a projection of those losses and costs into the future. The Department presents its specific load growth and electricity price trends in the LCC Inputs section (section 8.3) of this chapter.

8.2.2.6 Step #6: Select Discount Rate

Step #6: The spreadsheet model selects a discount rate from the discount rate distribution. To discount the future stream of costs into a present value, it is necessary to select a discount rate. The LCC spreadsheet selects a discount rate from a weighted sample of discount rate inputs derived from observed returns on investment and financing costs for transformer purchasers. The Department presents its specific discount rates in the LCC Inputs section (section 8.3) of this chapter.

8.2.2.7 Step #7: Calculate Present Value of Future Cost of Losses

Step #7: The spreadsheet model calculates the present value of future operating costs and losses and the present worth per watt of no-load and load losses. This step applies the discount rate of Step #6 to the future costs of losses from Step #5 to produce a single, present-valued number. In addition to the costs from Step #5 above, the calculation uses as inputs the effective date of the standard, the transformer lifetime, maintenance costs, and power factor.

8.2.2.8 Step #8: Results Reported

Step #8: The spreadsheet model records the LCC, LCC savings, payback period, and other results for inclusion in the distribution of results. This is a reporting step. The model uses the inputs in a set of calculations and reports the results. Depending on the application, different kinds of results can be reported, e.g., LCC savings, payback periods, or equivalent A and B values. The default report includes LCC savings for each candidate standard level over the baseline scenario; it reports the mean value, plus the percentage of purchasers with positive LCC savings. Payback periods are reported separately.

8.2.2.9 Step #9: Results of Distribution of Transformers

Step #9: The spreadsheet model repeats the calculation until reaching the specified maximum number of iterations. When applying a Monte Carlo simulation process, the model performs a user-defined number of iterations and reports the results as distributions. Based on the Department's experience with prior rulemakings using results expressed as distributions, 10,000 iterations in a Monte Carlo simulation capture sufficient variability.

8.2.2.10 Step #10: Results for "Average" Scenario

Step #10: The spreadsheet model reports the results of the calculation for the "Average" scenario on the "Summary" worksheet. The "Average" scenario allows users to produce provisional answers without performing a Monte Carlo simulation. The Summary Worksheet of the LCC spreadsheet shows the results from this scenario. For liquid-immersed transformers, the Department extracted the marginal demand cost and marginal energy cost used in the average scenario calculation from a representative LCC Monte Carlo simulation. Similarly, for dry-type transformers, the Department extracted an average marginal demand and energy rate from a sample dry-type Monte Carlo simulation.

8.2.2.11 Repeat Process

The specific number of iterations required for the Monte Carlo simulation is implemented through the <Repeat Process> decision box. When the desired number of iterations has been reached, the model ends the simulation process and generates result reports.

8.3 LCC INPUTS

This section presents the specific LCC inputs used in the spreadsheet model and provides definitions and data sources for each component. This section also elaborates on the specifics of how the LCC spreadsheets apply certain user-chosen inputs to the LCC model. The specific inputs to the model, in the order in which they appear in the left-hand side of the LCC flowchart (Figure 8.2.1), are:

- A and B Transformer Selection Parameters and Usage Rates
- Database of Transformer Designs
- Markup and Installation Costs
- Transformer Loading
- Electricity Costs and Prices
- Load Growth Trends
- Electricity Cost and Price Trends
- Discount Rate

- Effective Date of Standard
- Transformer Service Life
- Maintenance Costs
- Power Factor

8.3.1 A and B Transformer Selection Parameters and Usage Rates

The A and B transformer selection parameters that DOE used in the formal TOC calculation can also be used more generally to characterize the value that transformer purchasers place on reducing no-load and load losses in transformers. This is because the A and B parameters express a measure of the economic value of loss reduction in terms of dollars per watt of reduced losses. The ability to measure the economic value of loss reduction in units of dollars per watt is independent of the actual method for estimating that value. The main assumption implicit in using A and B values to represent customer transformer choice decisions is that the value of loss reduction is proportional to the amount by which losses are reduced. Given this wider applicability of the TOC formulation to the expression of loss valuations, the Department used A and B parameters to formulate a transformer customer choice model.

To represent the potential range of purchaser valuations given to transformer no-load and load losses, the Department developed three A and B distributions to represent three customer choice scenarios for each LCC calculation. The key difference among the three scenarios is the fraction of purchasers who are estimated to place a value on reducing transformer losses. Those who place a value on reducing such losses are described as "evaluators," while those who do not consider transformer losses during a purchase are termed "non-evaluators." The scenario representing non-evaluation for all purchases has 0 percent evaluators, while the scenario representing evaluation for all purchases has 100 percent evaluators. For liquid-immersed transformers, many purchases are evaluated, so the Department's default scenario is the medium evaluation rate of 50 percent, which is consistent with recommendations made by NEMA.[3] Table 8.3.1 provides the evaluation usage rates, for the three evaluation scenarios just described, for a range of different A values for liquid-immersed transformers. For dry-type design lines, few purchasers consider transformer losses as part of the purchase decision, so DOE developed a default medium scenario with 10 percent of evaluators, which is consistent with data developed for the Department's original *Determination Analysis* for transformers.[4] Table 8.3.2 provides the evaluation usage rates, for the three evaluation scenarios just described, for a range of different A values for dry-type transformers. The 0 percent and 100 percent evaluation scenarios are available to test the LCC sensitivity to changes in the percentage of transformers purchased using evaluation to select transformers.

Lacking detailed data on A values used in TOC calculations, the Department estimated the mean value of A for evaluators by using an average electricity cost of $0.06 per kWh, assuming a mean payback time of 10 years for evaluating customers and rounding to the nearest dollar per watt (8760 hours/year * $0.06/kWh * 10 years ~ $5/watt). Then, recognizing that there is substantial variability in the value that transformer purchasers may place on reducing losses, the Department created a distribution that represented this variability, as illustrated in

Tables 8.3.1 and 8.3.2. The Department did not have data to allow it to distinguish between the A values used by evaluating purchasers of liquid-immersed and dry-type transformers, so the Department used the same-shaped distribution for A for the two types of transformers.

For each value of A that a transformer purchaser may have, there is a range of possible B values that are consistent with the particular A value. (B values relate to the value associated with the load losses.) In general, the ratio of B to A is a measure of the relative importance of load losses and no-load losses. For a transformer that is constantly loaded at 100 percent of rated capacity, the value of B and A should be the same, since both load and no-load losses will always be at their rated values. Load losses decrease with the square of the loading, and transformer mean loadings are almost always below 100 percent. Therefore, in practice, B is always less than A, and is approximately equal to A times the square of the expected loading (when peak load considerations are neglected).

The Department characterized the relationship between customer selection of B and A values by selecting five possible values for the B:A ratio. For liquid-immersed transformers, the Department selected a B:A ratio of 0.25 (the square of 50 percent) as a reasonable median value, based on the NEMA-recommended evaluation point of 50 percent loading for medium voltage transformers. For dry-type transformers, the Department estimated the median ratio of B:A as the square of the root mean square transformer loading estimated by the Department. To model variability in the ratio of B:A, the Department selected four other values for the ratio between 0 and 1: 0.33 * MedianBA, 0.66 * MedianBA, 0.2 + 0.8 * MedianBA, and 0.5 + 0.5 * MedianBA, where MedianBA is the median value of the B:A ratio. These four values of the ratio provide an approximately even distribution between 0 and 1 that has the estimated median value for the B:A ratio.

As described above, the Department selected slightly different median B:A ratios for liquid-immersed and dry-type transformers. The higher B:A ratio for liquid-immersed transformers reflects the more careful evaluation of peak load impacts of load losses on the part of utilities. The B:A ratio for dry-type customers reflects an assumption that commercial and industrial customers will tend to value their load losses with an average electricity price.

The Department calculated present work factors for no-load and load losses so that stakeholders could compare between the Department's LCC results with the A and B values used in TOC calculations. The Department defines the present worth factor for transformer losses as the present value of losses divided by the rated loss. There are distinct present worth factors for no-load and load losses. The present worth factor is different from the A and B values used by for TOC calculations because the method for calculating the present value of losses is consistent with the methods of efficiency standard LCC calculations and differs slightly from the method described in the Institute of Electrical and Electronics Engineers' *Draft Guide for Distribution Transformer Loss Evaluation.*[2]

To summarize, the Department characterized transformer purchases with respect to efficiency in terms of two economic valuation parameters. The parameter A expresses the value that a customer gives to reducing no-load losses in dollars per watt, while the parameter B expresses the value given to reducing load losses at rated load. The Department described purchase behavior in terms of "evaluators" who place a value on reducing losses, and "non-evaluators" who place no value on reducing losses in their purchase behavior. The Department investigated three scenarios as sensitivities. For liquid-immersed transformers, the scenarios are 0 percent evaluators, 50 percent evaluators, and 100 percent evaluators; for dry-type transformers, the scenarios are 0 percent evaluators, 10 percent evaluators, and 100 percent evaluators. For evaluators, the Department uses a distribution of A and B values to characterize their behavior. The mean of the distribution of A values corresponds approximately to an electricity price of $0.06/kWh and a 10-year payback time for investments. Once it chose the A value, then DOE chose a value of B, less than A, using a B:A ratio. The Department based the B:A ratio on an estimated range of transformer loadings provided by the energy use and end-use load characterization analysis (Chapter 6).

Table 8.3.1 Distributions of A Values for Liquid-Immersed Transformers: Three Scenarios with Usage Percentages

0% Non Evaluating	
A ($)	**Probability (%)**
0.00	100.00

50% Med Evaluating	
A ($)	**Probability (%)**
0.00	50.00
0.63	0.93
1.25	1.87
1.88	2.80
2.50	3.74
3.13	4.36
3.75	4.98
4.38	4.98
5.00	4.98
5.63	4.48
6.25	3.99
6.88	3.32
7.50	2.66
8.13	2.09
8.75	1.52
9.38	1.14
10.00	0.76
10.63	0.55
11.25	0.34
11.88	0.24
12.50	0.13
13.13	0.09
13.75	0.05

100% High Evaluating	
A ($)	**Probability (%)**
0.00	0.00
0.63	1.87
1.25	3.74
1.88	5.61
2.50	7.47
3.13	8.72
3.75	9.96
4.38	9.96
5.00	9.96
5.63	8.97
6.25	7.97
6.88	6.64
7.50	5.31
8.13	4.18
8.75	3.04
9.38	2.28
10.00	1.52
10.63	1.10
11.25	0.67
11.88	0.47
12.50	0.27
13.13	0.18
13.75	0.10

Table 8.3.2 Distributions of A Values for Dry-Type Transformers: Three Scenarios with Usage Percentages

0% Non Evaluating	
A ($)	**Probability (%)**
0.00	100.00

10% Med Evaluating	
A ($)	**Probability (%)**
0.00	90.00
0.63	0.19
1.25	0.37
1.88	0.56
2.50	0.75
3.13	0.87
3.75	1.00
4.38	1.00
5.00	1.00
5.63	0.90
6.25	0.80
6.88	0.66
7.50	0.53
8.13	0.42
8.75	0.30
9.38	0.23
10.00	0.15
10.63	0.11
11.25	0.07
11.88	0.05
12.50	0.03
13.13	0.02
13.75	0.01

100% High Evaluating	
A ($)	**Probability (%)**
0.00	0.00
0.63	1.87
1.25	3.74
1.88	5.61
2.50	7.47
3.13	8.72
3.75	9.96
4.38	9.96
5.00	9.96
5.63	8.97
6.25	7.97
6.88	6.64
7.50	5.31
8.13	4.18
8.75	3.04
9.38	2.28
10.00	1.52
10.63	1.10
11.25	0.67
11.88	0.47
12.50	0.27
13.13	0.18
13.75	0.10

8.3.2 Database of Transformer Designs

Establishing a relationship between cost and efficiency is an integral part of the rulemaking process. For transformers, DOE derived this relationship from an engineering analysis database of selling prices, no-load losses, and load losses for a wide range of realistic transformer designs contained in the LCC spreadsheets. The Department used a commercial transformer design software company, Optimized Program Service Inc., and its software to create the database of designs. The database consists of a wide range of efficiencies and manufacturer sale prices (including a predetermined manufacturer markup) to represent the variability of designs in the marketplace. The engineering analysis (see Chapter 5) provides more detail on the structure and method used to generate this database of transformer designs.

8.3.3 Markup and Installation Costs

Markup, shipping costs, sales tax, and installation costs are the costs associated with bringing a manufactured transformer into service as an installed piece of electrical equipment. Since electric utilities typically purchase liquid-immersed transformers directly from manufacturers, the manufacturer selling price is the utilities' price for these transformers. Dry-type transformers go through several additional steps before the final transformer cost is determined. The Department subjected the manufacturing costs of dry-type transformers to three price markups: a manufacturer markup, a distributor markup, and a contractor markup. The markup analysis is detailed in Chapter 7.

8.3.4 Transformer Loading

To estimate the economic burdens and benefits of efficiency improvements, the Department characterized the energy use and losses of the equipment being analyzed. To characterize transformers' energy use and losses, the Department estimated the loads on them. Because the application of distribution transformers varies significantly by type of transformer (liquid-immersed or dry-type) and ownership (electric utilities own liquid-immersed 95 percent of the time, commercial/industrial entities use mainly dry-type), the Department performed two separate load analyses for use in the evaluation of distribution transformer efficiency: it performed one load analysis for liquid-immersed transformers that are used mainly by electric utilities, and it performed a second load analysis for dry-type transformers that are used mainly by C&I customers. Chapter 6 describes these two separate load analyses.

8.3.5 Electricity Price Analysis

This section describes the electricity price analyses the Department used to develop the energy portion of the annual operating expenses for distribution transformers. The electric power industry is currently in a state of transition between two different business models, from regulated monopoly utilities providing bundled service to all customers in their service area, to a system of deregulated, independent suppliers who compete for customers. While it is unclear when this transition will be completed, it is possible that, in the near future, customers will see a very different pricing structure for electricity. To account for the impacts of this change on the LCC, the Department performed two types of load analysis for use in the evaluation of distribution transformer efficiency. The first type of analysis investigated the nature of hourly transformer loads, their correlation with the overall utility system load, and their correlation with hourly electricity costs and prices. The second type of analysis estimated the impacts of transformer loads and the resultant transformer losses on the monthly electricity usage, demand, and electricity bills of C&I customers. The Department refers to the two analyses as "hourly" and "monthly" analyses, respectively. The Department used the hourly analysis for the economic analysis of liquid-immersed transformers, which are predominantly owned by utilities that see costs that vary by the hour. The Department used the monthly analysis for the evaluation of dry-type transformers, which are typically owned by C&I establishments that see monthly electricity bills.

8.3.5.1 Hourly Marginal Electricity Price Model for Liquid-Immersed Transformers

For liquid-immersed transformers, the Department used marginal electricity prices. Marginal electricity prices are the prices experienced by utilities for the last kilowatt-hours (kWh) of electricity produced. A utility's marginal price can be higher or lower than its average price, depending on the relationships between capacity, generation, transmission, and distribution costs. The general structure of the hourly marginal cost equation divides the costs of the electricity into capacity components and energy cost components. The capacity components include generation capacity, transmission capacity, and distribution capacity. Capacity components also include a reserve margin needed to ensure system reliability. Energy cost components include a marginal cost of supply that varies by the hour, factors that account for losses, and cost recovery of associated marginal expenses. The Department applied this specific equation to calculate the marginal cost of supply of electricity to cover transformer losses. The equation is:

$$MEC = (1 + CM) * (GC * IGC + TC * ITC + DC * IDC) + (LAF * EC(hour) + RF) * IEU(hour) \qquad \textbf{Eq. 8.3}$$

where:

MEC = marginal electricity cost,
CM = system capacity margin required for reliability,
GC = unit cost of generation capacity,
IGC = incremental system capacity required by the load,
TC = unit cost of transmission capacity,
ITC = incremental transmission capacity required by the load,
DC = unit cost of (non-transformer) distribution capacity,
IDC = incremental distribution capacity required by the load,
LAF = system loss factor, which is one plus the estimated system losses,
$EC(hour)$ = hourly cost of electrical energy, either from a market or from fuel and operating cost data,
RF = additional cost recovery factor, and
$IEU(hour)$ = incremental energy use.

The Department calculated the various inputs of this equation as follows:

Capacity Margin (CM): This is the fraction of extra or reserve capacity needed to ensure system reliability per unit of additional capacity requirement. The Department used the industry standard of 15 percent.

Unit Generation Capacity Cost (GC): This is the annualized cost-of-unit generating capacity for the particular load being served. It includes the cost of capital during the construction period, and the loss adjustment factor to account for losses between the generator and end-use load. The *Annual Energy Outlook 2003 (AEO 2003),* published by the EIA, provides forecasts of such costs for different generation technologies.[5] This capacity cost depends on the type of load being served and the source of the electricity. For base load, DOE used the capacity cost for a pulverized coal plant, since this is currently the least-cost base-load technology. For peak loads, such as those associated with transformer peak-load losses, the Department used conventional combustion turbine capacity costs as the relevant marginal capacity cost. The Department obtained its estimates for generation capacity costs from data and estimates contained in the *AEO 2003* forecast. These costs are shown in Table 8.3.3.

Table 8.3.3 Generation Capacity Costs

Technology	Year	Cost (2000$/kW)
Conventional Pulverized Coal	2001	1,119
	2010	1,083
	2020	1,056
Conventional Gas Combined Cycle	2001	456
	2010	448
	2020	438
Conventional Gas Combustion Turbine	2001	339
	2010	333
	2020	326

Incremental Generation Capacity Requirement (IGC): This is the amount of generation capacity required by a load. For the core loss component, this is equal to the core losses times the loss adjustment factor (see LAF below). For the load-loss component, DOE estimated this by multiplying the peak responsibility factor (PRF) by the transformer peak load and feeding the result to the load-loss equation. The peak responsibility factor is the fraction of the transformer peak that is coincident with the system peak. The Department calculated a first-year peak responsibility factor. Note that there is a multi-year delay between when new capacity is contracted and when it becomes available. *AEO 2003* capacity cost forecasts are expressed in terms of when the capacity is contracted. The Department translated this cost into the cost at first year of service by adding capital costs as determined by the discount rate. The Department annualized costs by applying the capital recovery factor to capacity costs, assuming that such capacity has a 30-year lifetime.

Unit Transmission Capacity Cost (TC): This is the annualized cost per unit for an increment of new transmission capacity. The Department obtained transmission capacity costs from the estimates made by EIA for each of 13 transmission regions in the *AEO 2003* forecast. The Department used the value of $166/kW, which is the average marginal transmission capacity cost for all 13 transmission regions.

Incremental Transmission Capacity Requirement (ITC): This is the amount of transmission capacity required by an incremental load. The Department assumed that the transmission capacity requirement is the same as the generation capacity requirement.

Unit Distribution Capacity Cost (DC): This is the cost per unit of distribution capacity. The Department used distribution capacity costs from the U.S. Federal Energy Regulatory Commission (FERC) Form 1 data on the investment in transformers, substations, lines, and feeders per unit of system peak[6] as analyzed and published by the Regulatory Assistance Project.[7] The Department used the average cost of distribution capacity per kilowatt of system peak, and assumed that the real price of distribution capacity is constant (i.e., has no trend up or down). The estimated distribution capacity cost for the analysis is $276/kW.

Incremental Distribution Capacity Requirement (IDC): This is the amount of distribution capacity required by an incremental load. The Department assumed this to be the same as the peak incremental energy use.

Loss Adjustment Factor (LAF): The loss adjustment factor is the factor that one must multiply times an end-use load to estimate the amount of system electricity needed to supply that load. It is one plus the fractional losses in the system. The Department assumed it to have a constant value of 1.08.

Hourly Energy Cost (EC): This is the hourly marginal energy cost that DOE obtained from utility system lambda data or market data. Since DOE obtained this from market data, it assumed it to include generation capacity effects and the generation capacity cost to be zero.

Additional Cost Recovery Factor (RF): This is a factor that DOE added to the hourly energy cost to account for costs besides energy losses that are associated with supplying that energy. The Department obtained the per-kWh additional cost recovery factors in Table 8.3.4 using real-time pricing formulas from the utilities listed in the table. Such factors are necessary for marking up the cost of generation to account for other costs that scale with generation, but which are not included in such costs. Such costs may include accounts payable and accounts receivable and operating capital costs, which will have a component that scales with the volume of electricity sales.

Table 8.3.4 Representative Cost Recovery Factors

Utility	Recovery Factor
Illinois Power Company	0.5 cents/kWh (five-year contract)
Pacific Gas and Electric Co.	0.346 cents/kWh
PSI Energy Inc.	10% to 25% of EC(hour)*LAF
Carolina Power and Light	20% of EC(hour)
Union Light, Heat, and Power Company	10% of EC(hour)*LAF

Based on this range of observed cost-recovery factors, DOE assumed that the cost recovery factor is approximately 0.15 (i.e., 15 percent) of the cost of energy.

Incremental Energy Use (IEU): This is the incremental hourly energy use calculated from the transformer loading that is obtained from the formula for the transformer losses.

8.3.5.2 Monthly Analysis

This section gives an overview of the tariff-based analysis of electricity prices.

Selection of the Sample Utilities. The Department used three main criteria in developing the utility sample for the utility tariff formulas: 1) The sample of utilities should reflect the distribution of population across the country, with more utilities drawn from more populated areas; 2) The sample should reflect the proportion of customers served by privately owned (investor-owned utilities or IOUs and power marketers) entities, versus publicly owned utilities (municipals, cooperatives, state, and federal); and 3) The sample should cover as many customers as possible. Data on utilities are available from the EIA through their Form 861 filings.[8] This form is filed annually by every utility that retails power to final consumers, and includes information on the total sales in MWh, total revenues, and the numbers of customers. Utilities supply this information separately for the residential, commercial, and industrial sectors. The Department used data from the year 2000 in this analysis.

The Department first screened the set of utilities in the EIA database, to consider only those with customers in all three sectors (residential, commercial, industrial). It then computed, for each subdivision, the percentage of customers served by public versus private utilities. The Department chose the sample utilities to reflect the relative population of the subdivision and the proportion of public-to-private customers. In most areas, the Department included the largest utilities in the sample to maximize the number of customers represented, but it also included smaller private utilities and public utilities of all sizes. The final set of sampled utilities includes 49 privately owned and 41 publicly owned companies.

The EIA data for 2000 show that power marketers and other providers of unbundled retail services serve approximately 2 percent of the commercial customers in the country. Power marketers have the largest market share in New England, so the Department included one such company in its sample for this region. Appendix 8C contains a list of the sample utilities.

Subdivision of the Country. Because of the wide variation in electricity usage patterns, wholesale costs, and retail rates across the country, it is important to consider regional differences in models of electricity prices. For this reason, the Department divided the continental United States into 17 regions or subdivisions. To make maximum use of the location information in DOE's Commercial Building Energy Consumption Survey (CBECS), the breakdown started with the nine census divisions. The Department further subdivided these to take into account significant climate variation and the existence of different electricity market or grid structures. The Department based climate divisions on the nine climate regions defined for the continental U.S. by the National Climactic Data Center.[9] In addition, it separated out Texas, Florida, New York and California, because their electric grids are operated independently. Figure 8.3.1 illustrates the results. In Figure 8.3.1 the subdivision numbers use the CBECS census code as the first digit. For example, census division 8 (Mountain) has been separated into two subdivisions 8.1 and 8.2.

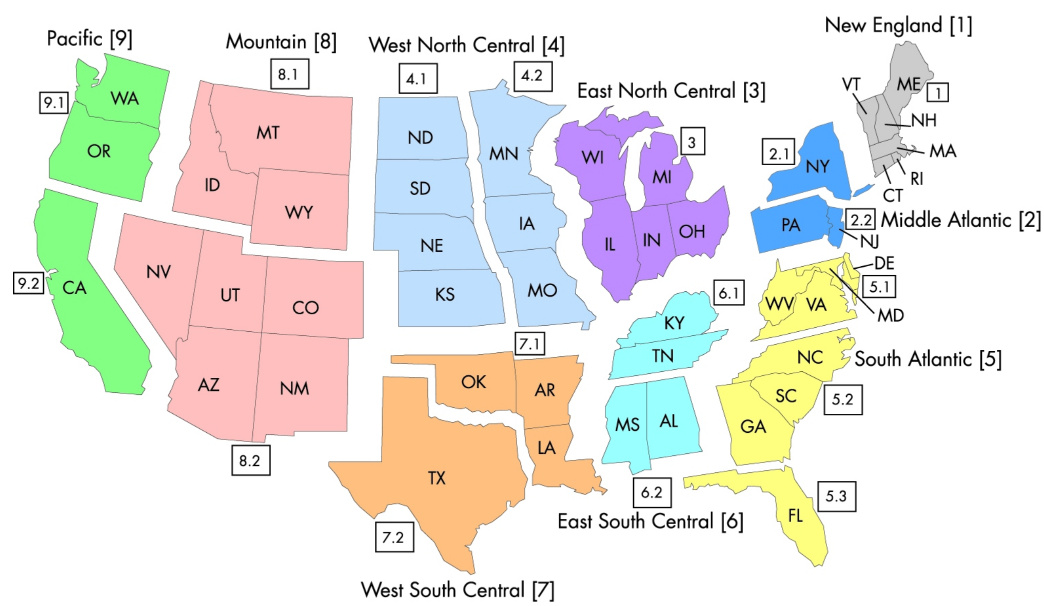

Figure 8.3.1 Map showing the Division of the Continental United States into 17 Subdivisions

Representativeness of the Sample. For this rulemaking, the Department defined the representativeness of the sample by the percentage of the total number of C&I customers who were covered. It is relatively easy to get good representation for IOUs, because in most regions there are a few large companies serving many customers. It is more difficult to represent the publicly owned companies, as these tend to be much smaller; to obtain the same level of customer representation, DOE would need to include many more utilities. The sampled utilities serve 60 percent of the C&I customers of private utilities, and 14.4 percent of C&I customers for public utilities. The combined total for the U.S. is 48.5 percent of all C&I customers. Table 8.3.5 gives the percentage of customers by subdivision, broken down by ownership type.

Table 8.3.5 Percentage of All C&I Customers, by Subdivision, in the Utility Sample

Subdivision	Census Division	Region	Public Customers in Sample *(%)*	Private Customers in Sample *(%)*	Fraction of Total Customers in Sample *(%)*	Number of Customers in Sample
1	New England	New England	3.7	43.9	40.3	310,505
2.1	Middle Atlantic	New York	88.2	72.4	74.7	671,407
2.2	Middle Atlantic	PA, NJ	7.9	50.6	49.4	504,466
3	East North Central	WI,IL,IN,OH,MI	8.5	43.5	39.1	831,124
4.1	West North Central	MN, IA, MO	5.4	27.0	12.4	44,823
4.2	West North Central	ND,SD,NE,KS	9.8	59.0	46.5	387,603
5.1	South Atlantic	DE,MD,VA,WV	13.4	72.9	67.5	552,058
5.2	South Atlantic	NC,SC,GA	11.8	88.9	64.3	778,500
5.3	South Atlantic	Florida	15.1	72.0	58.4	530,513
6.1	East South Central	KY,TN	11.5	47.2	20.6	128,694
6.2	East South Central	MS,AL	9.9	68.5	42.9	217,970
7.1	West South Central	OK,AR,LA	3.5	60.4	44.1	265,412
7.2	West South Central	Texas	18.2	23.8	22.2	272,077
8.1	Mountain	MT,ID,WY	10.5	52.2	39.6	70,323
8.2	Mountain	NV,UT,CO,AZ,NM	5.9	71.8	46.2	310,765
9.1	Pacific	WA,OR	16.5	47.9	38.1	243,271
9.2	Pacific	California	20.3	97.4	75.8	1,050,862
	National Sample	USA	14.4	60.0	48.5	7,170,373

The ratio of total revenues to total energy sales—which reflects, on an average basis, the amount of money collected for each kWh sold—also varies significantly between utilities and across different regions. Figure 8.3.2 illustrates the degree of variation. The figure plots the customer-weighted average of utility revenues divided by sales (in units of $ per kWh) within each subdivision. The vertical bars show the average value, plus or minus one standard deviation, for all the utilities in the EIA data. The points show the customer-weighted average revenues divided by sales for the sampled utilities only. There is a large spread in the EIA data, and sample averages are within this range.

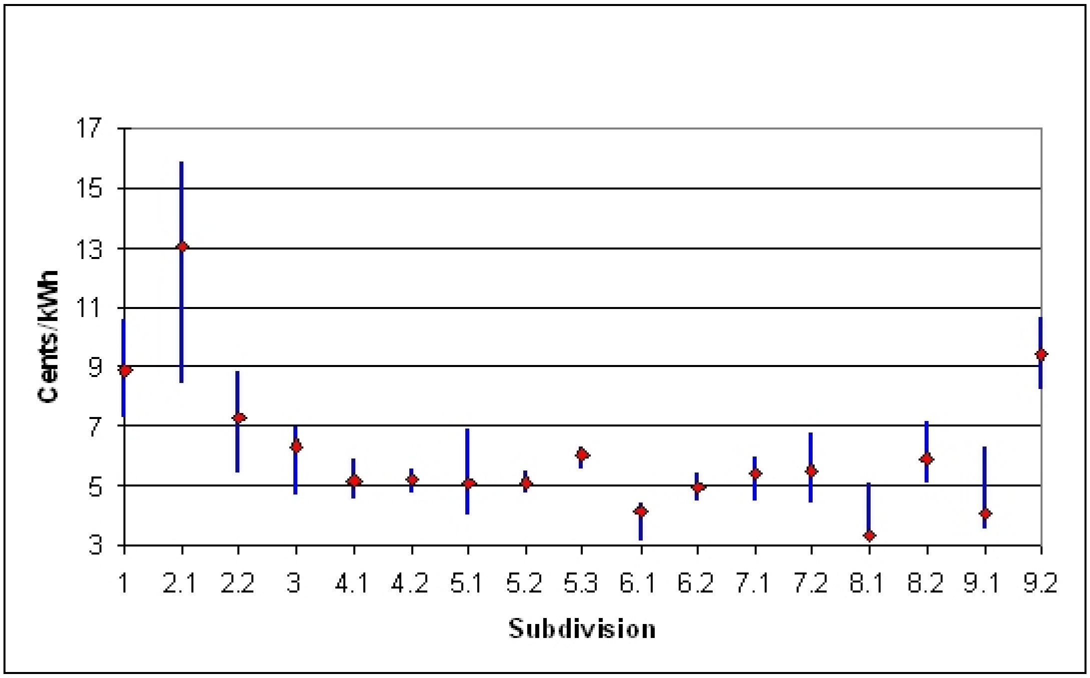

Figure 8.3.2 Customer-Weighted Average per kWh Revenue

Utility weights. The way in which the Department assigned weights to the utilities depended on the application. As will be discussed in more detail below, the marginal rate seen by a particular customer depends both on the tariff and on that customer's energy use characteristics.

For this case, the appropriate weight for the utility is the number of customers it has, divided by the number of customers in the subdivision. The weights for all the utilities in a given subdivision will then add up to one. Because the level of customer representation for public utilities is much less than for private ones, the Department included an additional factor to account for the difference, so that the total weight of the sample public utilities equals the fraction of public customers in that subdivision.

The weight for utility k is:

$$Weight(k,own\_type) = (\ n(k,own\_type)/n(own\_type)\ ) * (\ N(own\_type)/N), \qquad \textbf{Eq. 8.4}$$

where own_type = public or private. By definition,

$$\sum(own\_type)\sum(k)\ Weight(k,own\_type) = 1. \qquad \textbf{Eq. 8.5}$$

where:

n(k,pub)	=	number of customers served by publicly-owned sample utility k,
n(k,priv)	=	number of customers served by privately-owned sample utility k,
n(pub)	=	sum(k) n(k,pub) = total customers served by publicly-owned sample utilities,
n(priv)	=	sum(k) n(k,pub) = total customers served by privately-owned sample utilities,
N(pub)	=	total customers served by all publicly-owned utilities in the subdivision,
N(priv)	=	total customers served by all privately-owned utilities in the subdivision, and
N	=	N(pub) + N(priv) = total customers in the subdivision.

8.3.5.3 Data Collection and Modeling

This section briefly describes the data collection method, the selection of tariffs for a given utility, and how DOE modeled the tariffs.

Web search. The Department collected the vast majority of the tariff documents directly from utility web sites. Almost every privately owned utility in the sample makes its whole tariff structure available on the web, although not always in easily readable form. In many cases, the full tariff, as approved by the relevant State public utility commission, is published, and the actual customer rates have to be tracked down within this document. Many public utilities also put their rate information on the web. In cases where web documents were not available, the Department contacted the utilities directly. An archive of the documents the Department used in the analysis is available at http://eetd.lbl.gov/ea/ees/tariffs/index.php. The list of utilities in Appendix 8C also includes a uniform resource locator (URL) for each company.

Selection of tariffs for each utility. Utility companies have many tariffs, which are separated into residential, non-residential, and special-use—such as public street-lighting or agricultural. For the non-residential category, some utilities use the commercial-industrial distinction, but many do not; therefore, in its tariff database, the Department combined these into one customer category. The goal in collecting the tariffs was to cover the full range of C&I customer types for each utility. In most cases, the Department assigned customers to a specific tariff based on their peak demand over the previous 12 months. In a few cases, the assignment was based on the maximum monthly electricity consumption. Customers are not generally moved from one tariff to another.

Most utilities offer only one tariff for each customer size. Some of the larger utilities offer optional time-of-use (TOU) or real-time pricing (RTP) tariffs. Occasionally, utilities will offer different tariffs for different business types. In all of the cases checked, although the tariffs had different names, the rates were in fact the same. Some utilities do not specify rates for very large customers whose peak demand is on the order of thousands of kWs; instead they negotiate them on a case-by-case basis. For the LCC calculation, the Department used only tariffs that depend on usage and demand data (not TOU nor RTP tariffs), because the energy consumption data used included only monthly demand and usage.

The Department's sampling strategy was to take the default tariff for each customer class. The Department excluded "closed" tariffs; these are tariffs that are being phased out by the utility and so are not available to new customers. This suggests that such tariffs do not reflect rates that will be seen by the majority of customers in the future.

Utilities do not generally make information available on how many customers are on each tariff; however, this information is not actually needed for the LCC. Instead, what is important to know is the relative numbers of customers who use the distributed transformer equipment covered by the standard who are on different tariffs. The CBECS data on the building weights define the relative proportion of customers of different sizes (here size refers to the customer's peak load), and the building monthly load data provide the annual peak load—which DOE used to assign a customer to a tariff.

Modeling the tariffs. To calculate a customer's electricity bill requires two sets of inputs: the rates charged as defined by the tariff, and information on the customer's energy use. The customer data consist of the billing demand and total energy consumption for the current billing period. In its analysis, the Department assumed the billing period to be one calendar month. The billing demand is the customer's peak demand over the billing month. While the formulae determining the actual bill can be quite complex, they are based on three types of charges: fixed, energy, and demand. Fixed charges are those paid each month regardless of the level of energy use. They do not contribute to customer marginal rates and so do not have any impact on the operating cost savings used in the LCC. Energy charges are specified in units of ¢/kWh and depend on the customer's total energy consumption. Demand charges are specified in units of $/kW and depend on the customer's monthly billing demand. For most of the utilities in the sample, charges also vary seasonally.

Energy and demand charges are typically applied in blocks. This means that the customer pays one rate for energy use or demand up to a certain level, a second rate for usage up to the next level, etc. For example, in a tariff with three blocks, the energy charges may be 10¢/kWh for the first 200 kWh, then 8¢/kWh for the next 1,000 kWh, and 6¢/kWh for all remaining energy use. This is an example of declining block rates, where the energy charge decreases as the energy used increases. One may also see inclining block rates. As a variation on this theme, the block limits may depend on the customer's energy consumption and demand.

As an example of one such tariff, Figure 8.3.8 shows a block-by-demand tariff, which occur in about 20-30 percent of the utilities sampled. This figure is illustrative and does not reflect any particular utility. The first block has a rate of 10¢/kWh for the first 200 kWh of energy used. The second block rate is 6¢/kWh for energy consumption up to100 times the billing demand. The multiplier 100 is a tariff component with units of kWh/kW, which defines the width of the second block. The third block rate is 3¢/kWh for all subsequent energy use. Besides increasing the complexity of the calculation of the customer bill, this type of variable block size introduces a dependence of the energy charges on the billing demand. Two cases in Figure 8.3.3 illustrate this: in each case, the overall energy use is 3,200 kWh, but the billing demand is different (20kW versus 21 kW).

In Case 1, the customer energy use is 3200 kWh, and the monthly peak demand is 20 kW. The width of the second block is 100*20 = 2000 kWh. In dollars, the customer will pay: (0.10)*200 + (0.06)*2000 + (0.03)*1000 = 20 + 120 + 30 = 170.

In Case 2, the customer energy consumption is 3200 kWh, but the demand is 21 kW. Now the length of the second block is 2100 kWh, so the bill is: (0.10)*200 + (0.06)*2100 + (0.03)*900 = 20 + 126 + 27 = 173.

Even though the tariff specifies only energy charges, a change in the customer demand of one kW has increased the bill by $3.00. This is because 100 kWh of consumption have been shifted from the third, less expensive, block to the second, more expensive, block. Note that increasing the demand while holding the energy consumption fixed lowers the customer load factor, and in this case increases the effective marginal rate. This is a generic observation of the sampled tariffs.

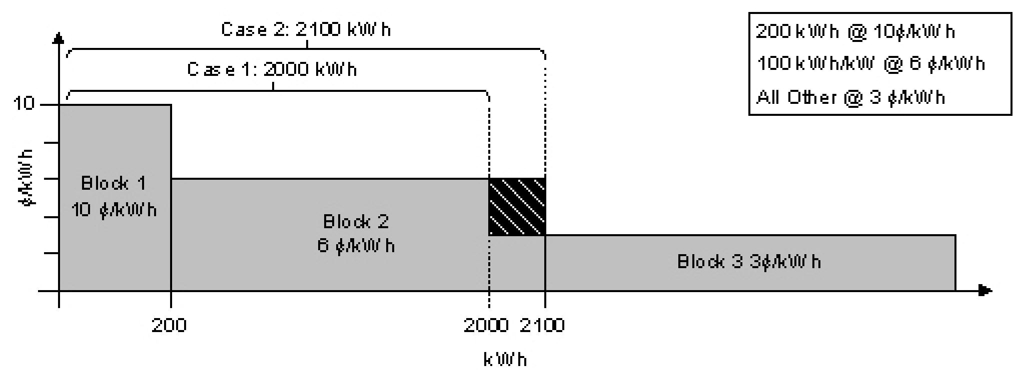

Figure 8.3.3 Effect of a Change in Customer Demand (Energy Consumption is Held Fixed) for a Block-by-Demand Tariff

The important point to take from this is that both demand and energy use contribute to the marginal rates seen by a customer, and often in ways that are not immediately obvious from reading the tariff. For the LCC, the energy cost savings due to the standard depends on the decrement to the total energy consumption, the decrement to the peak demand, and the ratio of the two. The effective marginal rate can vary substantially even for a set of customers on the same tariff.

***Approximations Used in Modeling the Tariffs*.** In cases where the available information on the full set of charges seen by the customer is incomplete, the Department made the following approximations:

- *Riders and adders*: Some tariffs, particularly in deregulated areas, include additional charges as riders which may not be explicitly defined. The most significant are the fuel-cost-recovery adders. These are additional charges passed on to the customer when the utility must spend more than anticipated for fuel. These costs are included when they are given explicitly; however, they are sometimes represented as a formula based on the utility's expenditures and so cannot be modeled within the Department's framework. This results in a possible underestimation of costs for some customers.

- *Customer classes*: In a few cases, the utility specifies tariffs for "small" and "large" customers, without giving an explicit definition of these terms. In its review of the tariffs in the sample, the Department found that small customers typically have a peak demand on the order of 10 kW, medium customers have a demand on the order of 100 kW, and large customers correspond to peak demands on the order of 1000 kW. The Department used a median value of 50 kW to separate customers into the "small" and "large" classes.

- *Ratchets*: Ratchets refer to situations where the billing demand for the current month is computed from a formula incorporating the monthly demand over the previous 12 months. For example, the billing demand may be set equal to either the current month's demand, or 80 percent of the maximum demand over the previous 12 months. A ratchet may also be seasonal. So, for example, the billing demand may be the greater of the current monthly demand or the peak demand in the most recent summer months. The Department did not include this type of rate formula in its tariff models. Instead, it assumed that the billing demand is the current monthly demand. The rationale behind ratchets is that demand charges are meant to cover capacity costs, and the actual capacity needed to serve a customer is better represented by their peak demand over a year rather than a month. New capacity is needed to serve a customer only when that customer contributes to the total system peak load, so one would expect that summer-peaking utilities would tend to implement ratchets that depend on summer demand. In these cases, the tariff model will underestimate the savings due to standards, since the billing demand decrement in each month will be somewhat less than the decrement for the summer months. The data collected on system loads show that all areas except the Northwest are summer-peaking in an average year. The southern states may have high loads during an especially cold winter, so these areas may implement ratchets that depend on the annual demand. In these cases, buildings with electric heat may have their peak demand occurring in the winter, and if the tariff includes a ratchet, the Department's model may over-estimate the savings due to standards.

Monthly Bill Calculations. The Department used the calendar month as the billing period. For each building, the Department used the peak demand and total energy consumption data from CBECS 1995 for 12 calendar months. The Department kept the customer on the same tariff for both the base and the standards cases. The Department calculated the monthly bills, adding the distribution transformer losses for both the base and the standards cases. The difference between the annual bills for each standard level gave the associated operating cost savings. The Department calculated the customer marginal demand and energy prices as the net change in the total bill, divided by the net change in demand or energy, respectively.

To represent the full range of tariffs in the spreadsheet, the Department created a Tariff Data Model (TDM). The TDM is a data structure used to store all of the tariff information in a format that is consistent across utilities. Briefly, the TDM divides each tariff into a collection of components. A component is defined by a set of parameters that include a rate, a range of values under which the rate applies, and indicator variables that specify if and when the rate should be applied. Using this component format, one can reconstruct the structure of any tariff from the set of components, and then apply the customer data used to determine whether conditions are met for a particular rate.

The Department input the TDM and the individual customer data into a Bill Calculator (BC), which is a set of accounting programs implemented as functions in an Excel® spreadsheet. These functions produce monthly bills for a customer. To present all the information on the collected tariffs in an accessible format, DOE implemented a version of the BC in a spreadsheet that includes customer data for a set of representative buildings. The spreadsheet allows the user to choose a utility and a particular tariff, and then choose from a set of buildings covered by that tariff. The spreadsheet calculates monthly bills for January and July for the chosen building, along with marginal rates and a breakdown of the bill into fixed, demand, and energy charges. The full information on the tariff is also displayed on the page. The BC spreadsheet can be obtained at http://tariffs.lbl.gov/

The TDM was the data structure used to store all of the tariff information. The objective of the TDM was to create a database structure that captured the complexity of a specific rate schedule (e.g., seasonal rates, variable block rates, mixtures of blocks, time-of-use tariffs) with sufficient accuracy to model any utility tariff. Having this consistent tariff model allows the user to make more precise comparisons of tariffs.

In principle, each tariff is simply a list of rates. However, a complete tariff is, in practice, often very complex. Typically, certain rules and conditions must be met for a particular rate to be applied. To capture this complexity, the TDM divides each tariff into a collection of components. A component is defined by a set of parameters that include a rate, a range of values under which the rate applies, and indicator variables that specify if and when the rate should be applied. Using this component format, the structure of any tariff can be reconstructed from the set of components.

TDM Rates. Each tariff component has a rate parameter. The rate stored in the TDM is a dimensionless, real, numbered value. The "charge type" indicator specifies the units for a particular component.

TDM Indicators.

Charge Type. The Charge-type indicator specifies the units for each component. The indicator is also used to keep track of charges as bills are calculated. There are three basic types of charges included in this sample: fixed charges, energy charges, and demand charges.

- Fixed charges ($/month) – These are typically monthly customer charges. Fixed rates are also used as minimum customer charges.

- Energy charges (¢/kWh) – These are the basic per-kWh charges associated with a tariff.

- Demand charges ($/kW) – These are the charges driven by peak consumption. Larger customers are typically subject to tariffs that incorporate demand charges.

Block Type. A block is the range in which a particular rate is applied. In general, these blocks are based on user consumption and demand. To determine these ranges, utilities use a variety of functions. In addition, a particular tariff may use different block functions for each block. However, at the component level, there is a small set of functions that can be used to set the limits of a range. In general, these limits are functions of kW of demand and kWh consumed (Limit = f {kW, kWh}). The block type indicates which limit function should be applied to each component. The Department modeled several functions.

- Fixed Block – This is the most common block type. The Department based the minimum and maximum limits on a predetermined kWh level.

- Block-By-Demand – This is also a common type, though less so then the fixed block. The maximum limit equals a *Demand Multiplier * User Demand*. In this case, the limit is not known until run time, when the user demand is known. (This type of block structure essentially incorporates a demand charge into an energy charge.) The min limit is set to the previous max.

- Mix Block Type 1 – The max limit is set by the max (*kWh*, *demand multiplier**kW). The min limit is set to the previous max.

- Mix Block Type 2 – The max limit is set by the min (*kWh, demand multiplier**kW). The min limit is set to the previous max.

- Mix Block Type 3 – The max limit is set by the sum (*kWh*, *demand multiplier**kW). The min limit is set to the previous max.

*TDM Ranges***.** The quantities that are used to determine limits are stored as ranges. The Department currently has ranges for seasonal limits and block limits.

- kWh Ranges – Min and max ranges for blocks are stored in units of kWh.

- kW Ranges – Min and max ranges for blocks are stored in dimensionless units. The block type indicator determines the unit for this range. Fixed blocks are in units of kW, other block types are the demand multiplier units, sometimes referenced by utilities as "Hours" or "kWh/kW."

- Month Range – Each utility defines the winter and summer months differently. The winter and summer start and end months are stored here.

- Season Type – The season type indicates in which season the component charge can be applied.

The Bill Calculator. The Bill Calculator is a set of accounting programs—implemented as functions—which can be accessed from within an Excel® spreadsheet. These functions produce monthly bills for a user, given the consumption, demand, and month. There are three functions of interest: *GetTariffs, GetCharges*, and *GenBills.*

GetTariffs. For a given utility, a customer is typically assigned to one of several tariffs. *GetTariffs* determines the tariff to which the user is assigned, given the peak consumption and peak demand levels.

GetCharges. GetCharges returns a monthly bill, given the tariff, consumption, and demand. This is the core function that reconstructs a tariff from the TDM. The function reads data from the TDM and evaluates which charges should be applied. It tallies these charges and returns the monthly bill in dollars.

GenBills. GenBills is basically a batch process that generates a large set of bills. GenBills reads input user data, e.g., consumption and demand, from an input file.

8.3.6 Load Growth Trends

The LCC analysis looks at a cross-section of transformers. The Department applied a load growth trend to each new transformer. Spreadsheet users have the choice of three scenarios using the Transformer Load Growth/Year drop-box on the "Summary" worksheet. The three scenarios for load growth are: no growth, one percent-per-year growth, and two percent-per-year growth. The Department used as the default scenario a one percent-per-year load growth for liquid-immersed transformers, i.e., a medium rate, as identified in the *Determination Analysis of Energy Conservation Standards for Distribution Transformers,* Report ORNL-6847.[10] For dry-type transformers, the Department used the no-growth scenario. The one percent annual load growth trend from ORNL-6847 is consistent with the average electricity use growth per customer during the 1990s, as determined by EIA. The Department applied a one perccent-per-year load growth trend to each new liquid-immersed transformer beginning in 2007, the expected effective date of the standard (see section 8.3.4). For dry-type transformers, installation of new circuits and transformers often accompanies new demand. The Department therefore expects load growth per dry-type transformer to be lower than for liquid-immersed transformers.

Figure 8.3.4 shows the cumulative growth for the default scenario of one percent-per-year load growth.

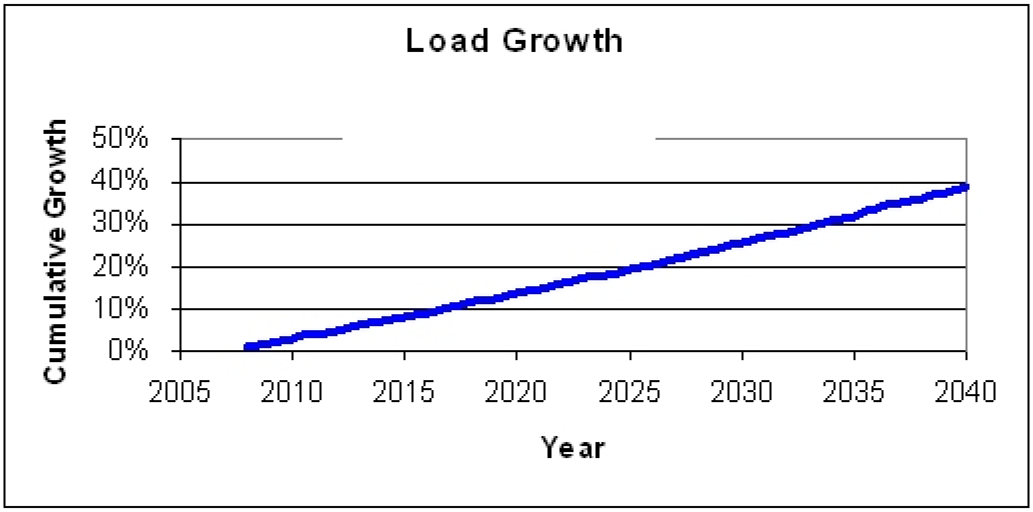

Figure 8.3.4 Cumulative Load Growth at 1 percent per Year

8.3.7 Electricity Cost and Price Trends

For the relative change in electricity cost and prices for future years, the Department used the price trends from three *AEO 2003* forecast scenarios from EIA.[5] LCC spreadsheet users have the choice of these three scenarios:

1. *AEO 2003* Low Growth scenario,

2. *AEO 2003* Reference scenario, and

3. *AEO 2003* High Growth scenario.

Figure 8.3.5 shows the trends for the three *AEO 2003* price projections. The Department extrapolated the values in later years (i.e., after 2025) from their relative sources because *AEO 2003* does not forecast beyond 2025. To arrive at values for these later years, the Department used the price trend of the forecast from 2015 to 2025 to establish prices in the years 2026 to 2035. This method of extrapolation is in line with methods currently used by the EIA to forecast fuel prices for the Federal Energy Management Program (FEMP).

The default electricity price trend scenario that DOE used in the LCC analysis is the trend from the *AEO 2003* Reference Case. Spreadsheets used in calculating the LCC have the capability to analyze the other electricity price trend scenarios, namely the *AEO 2003* High and Low Growth price trends.

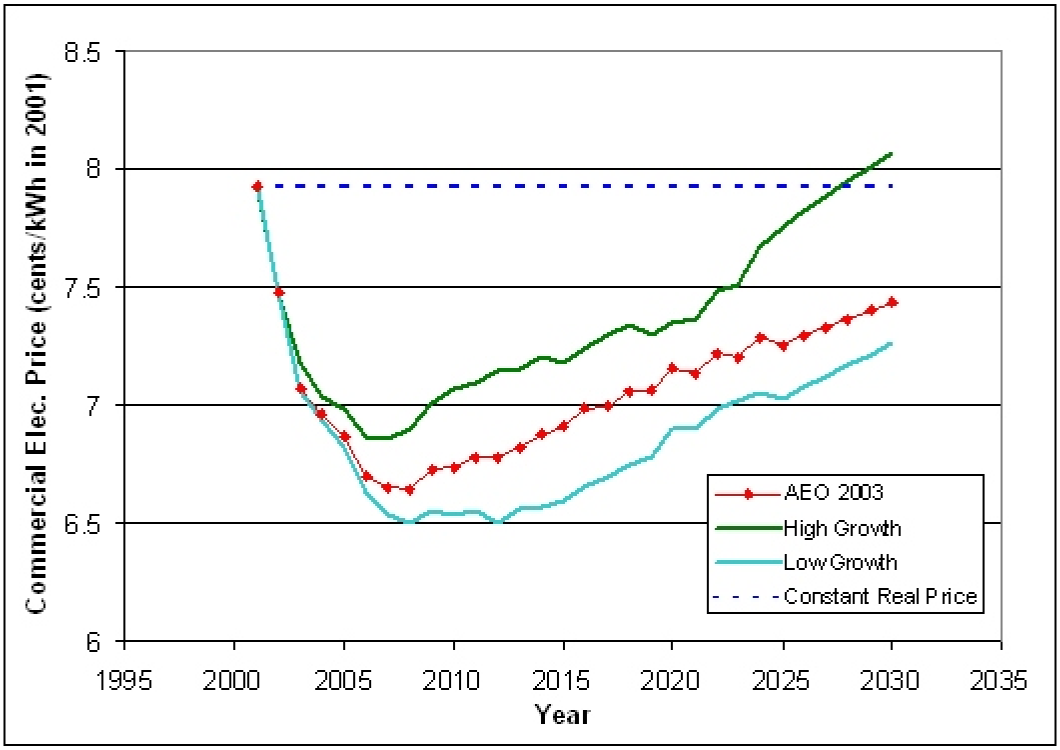

Figure 8.3.5 Electricity Price Scenarios

8.3.8 Discount Rate

The discount rate is the rate at which future expenditures are discounted to estimate their present value. The Department derived the discount rates selected for the transformer LCC analysis from estimates of the cost of capital for companies that purchase transformers. Following financial theory, the cost of capital can be interpreted in three ways: 1) It is the discount rate that should be used to reduce the future value of cash flows to be derived from a typical company project or investment; 2) It is the economic cost to the firm of attracting and retaining capital in a competitive environment; and 3) It is the return that investors require from their investment in a firm's debt or equity.[11] The Department primarily used the first interpretation. Most companies use both debt and equity capital to fund investments; for most companies, therefore, the cost of capital is the weighted average of the cost to the firm of equity and debt financing.[12]

The Department estimated the cost of equity financing using the Capital Asset Pricing Model (CAPM). The CAPM, among the most widely used models to estimate the cost of equity financing, assumes that the cost of equity is proportionate to the amount of systematic risk associated with a firm. For example, the cost of equity financing tends to be high when a firm faces a large degree of systematic risk, and the cost tends to be low when the firm faces a small degree of systematic risk.

The degree of systematic risk facing a firm and the subsequent cost of equity financing are determined by several variables, including the risk coefficient of a firm (beta), the expected return on "risk free" assets (R_f), and the additional return expected on assets facing average market risk (which is known as the equity risk premium, or ERP). The risk coefficient, or "beta," indicates the degree of risk associated with a given firm, relative to the level of risk (or price variability) in the overall stock market. Betas usually vary between 0.5 and 2.0. A firm with a beta of 0.5 faces half the risk of other stocks in the market; a firm with a beta of 2.0 faces twice the overall stock market risk.

Following this approach, the cost of equity financing for a particular company is given by the equation:

$$k_e = R_f + (B * ERP) \qquad \textbf{Eq. 8.6}$$

where:

k_e	=	the cost of equity for a company,
R_f	=	the expected return of the risk free asset,
B	=	the beta of the company stock, and
ERP	=	the expected equity risk premium, or the amount by which investors expect the future return on equities to exceed that on the riskless asset.

The cost of debt financing (k_d) is the yield or interest rate paid on money borrowed by a company (raised, for example, by selling bonds). As defined here, the cost of debt includes compensation for default risk and excludes deductions for taxes.

The Department estimated the cost of debt for companies by adding a risk adjustment factor to the current yield on long-term corporate bonds (the risk-free rate). This procedure is used to estimate current (and future) company costs to obtain debt financing. The adjustment factor is based on indicators of company risk, such as credit rating or variability of stock returns.

The discount rate of companies is the weighted average cost of debt and equity financing, less expected inflation. The Department estimated the discount rate using the equation:

$$k = (k_e * w_e) + (k_d * w_d) \qquad \textbf{Eq. 8.7}$$

where:

k	=	the (nominal) cost of capital,
k_e and k_d	=	the expected rates of return on equity and debt, respectively, and
w_e and w_d	=	the proportion of equity and debt financing.

The real discount rate deducts expected inflation from the nominal rate.

The expected return on "risk free" assets, or the risk-free rate, is defined by the current yield on long-term government bonds.[13] The ERP represents the difference between the expected (average) stock market return and the risk-free rate. As shown in Table 8.3.6, the Department used an ERP estimate of 5.5 percent, which was taken from the Damodaran Online site (a private website associated with New York University's Stern School of Business, that aggregates information on corporate finance, investment, and valuation).[14]

The Department calculated an expected inflation of 2.3 percent from the average of the last five quarters' change in Gross Domestic Product (GDP) prices.[15] The Department obtained the cost of debt, percent debt financing, and systematic firm risk from information provided at the Damodaran Online site.[a] Table 8.3.6 shows average values across all private companies. However, the cost of debt, percent debt financing, and systematic firm risk vary by sector. For example, average systematic firm risk of all private firms in the industrial sector is close to 1.0, while systematic firm risk in the utility sector averages close to 0.6.

Table 8.3.6 Variables Used to Estimate Company Discount Rates

Variable	Symbol	Average Value	Source
Risk free asset return	R_f	5.5%	Bloomberg Professional[16]
Equity risk premium	ERP	5.5%	Damodaran Online[14]
Expected inflation	r	2.3%	U.S. Bureau of Economic Analysis[15]
Cost of debt (after tax)	k_d	9.0%	Damodaran Online; FERC Form 1[6]
Percent debt financing	w_d	27%	Damodaran Online
Systematic firm risk	Beta	0.99	Damodaran Online

Transformers are purchased and owned by electric utilities (investor- and publicly owned), commercial and industrial companies, the owners of commercial buildings (property owners), and the government. Table 8.3.7 shows the typical owners of transformers, grouped by

[a] The Department estimated percent debt for firms in the property-owning category using data from Bloomberg Professional.[16] The Department took the cost of debt for publicly owned utilities from FERC Form 1 filings.[6]

the design lines used in the engineering analysis. The Department used a sample of 4,294 companies drawn from these owner categories to represent transformer purchasers. It took the sample from the list of companies included in the *Value Line* investment survey[17] and listed on the Damodaran Online site. The Department obtained the cost of debt, the firm beta, the percent of debt and equity financing, the risk-free return, and the equity risk premium from Damodaran Online.

The Department estimated the cost of debt financing for these companies from the long-term government bond rate and the standard deviation of the stock price.[14] Publicly owned utilities, including municipals and cooperatives, do not issue stock and tend to be financed with debt. The Department obtained the cost of debt for these companies from information provided in FERC Form 1 filings. Finally, the government office discount rate represents an average of the Federal rate and the State and local bond rate. The Department drew the Federal rate directly from the U.S. Office of Management and Budget discount rate for investments in government building energy efficiency.[18] The Department estimated the State and local discount rate from the interest rate on State and local bonds between 1977 and 2001.[19] The Department used this information to estimate the weighted-average cost of capital for the sample of companies included in the property owner, commercial and industrial company, and utility database.

Table 8.3.7 Typical Owners of Different Types of Transformers

Design Line	Typical Ownership Categories
1, 2, 3, 4	Electric utilities, both public and investor-owned
5	Electric utilities, property owners, commercial and industrial companies, government offices
6, 7, 8, 9, 10, 11, 12, 13	Property owners, commercial and industrial companies, government offices

As previously mentioned, the cost of capital may be viewed as the discount rate that should be used to reduce the future value of typical company project cash flows. It is a nominal discount rate, since anticipated future inflation is included in both stock and bond expected returns. Deducting expected inflation from the cost of capital provides estimates of the real discount rate by ownership category shown in Table 8.3.8. The mean real discount rate for these companies varies between 3.3 percent (government offices) and 7.5 percent (industrial companies).

Table 8.3.8 Real Discount Rates by Ownership Category

Ownership Category	SIC Codes	Mean Real Discount Rate	Standard Deviation	Number of Observations
Industrial Companies	1 - 4	7.5%	3.2%	2409
Commercial Companies	5 - 8	7.3%	4.7%	1773
Property Owners	6720	4.5%	0.9%	8
Utilities, Investor-Owned	49	4.2%	1.5%	63
Utilities, Publicly Owned		4.3%	1.1%	16
Government Offices		3.3%	2.1%	25

Source: Lawrence Berkeley National Laboratory (LBNL) calculations based on firms sampled from the Damodaran Online site.

Because investor-owned utilities purchase the bulk of many transformer design lines evaluated here, the discount rates calculated for that sector (Table 8.3.8) are particularly important. The Department estimated that the average investor-owned utility real discount rate is 4.2 percent. The 4.2 percent figure is an after-tax discount rate, representing the return required by such utilities to attract financing. Private financial data companies, including Ibbotson Associates and Bloomberg Professional, offer similar estimates. The Bloomberg Professional online service estimates the cost of investor-owned utility capital to be 4.4 percent.[a] Ibbotson Associates estimates the cost of capital in this sector (SIC 49), after deducting 2.3 percent inflation, to be 5.0 percent.[20]

The Department's approach for estimating the cost of capital provides a measure of the discount rate spread as well as the average discount rate. The Department inferred the discount rate spread by ownership category from the standard deviation, which ranges between 0.9 percent and 4.7 percent (Table 8.3.8). Publicly owned utility and property owner discount rates are narrowly concentrated around their mean value. By contrast, commercial and industrial company discount rates are dispersed across a broader range.

Different combinations of property owners and commercial, industrial, and utility buyers purchase the different transformer design lines included in the engineering analysis (Chapter 5). Accordingly, the Department constructed the discount rates associated with any given design line from different combinations of property owner, commercial, industrial, and utility discount rates. For example, transformer design line 6 is purchased by property owners, commercial and industrial companies, and the government. Roughly 19 percent of customers are property

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[a] Average cost of capital, after deducting 2.3 percent inflation, for the set of investor-owned utilities sampled in this analysis. The Department obtained this estimate from the Bloomberg Professional service, during December, 2001.[16]

owners, 19 percent are industrial companies, 54 percent are commercial companies, and 7.9 percent are government offices (Table 8.3.9).

Thus, DOE constructed the discount rate appropriate for this design line from a differential weighting of property owners (19 percent), industrial companies (19 percent), commercial companies (54 percent) and government (7.9 percent).[21] The Department constructed other transformer design line discount rates from a weighting of property owner, industrial, and commercial discount rates.

Table 8.3.9 Transformer Ownership by Design Line

Transformer Design Line	Property Owners	Industrial Companies	Commercial Companies	Investor-Owned Utilities	Publicly Owned Utilities	Government
1	0.4%	0.5%	0.9%	72.0%	26.0%	0.2%
2	0.4%	0.5%	0.9%	72.0%	26.0%	0.2%
3	2.1%	2.4%	4.5%	80.0%	10.0%	1.0%
4	0.4%	0.5%	0.9%	72.0%	26.0%	0.2%
5	9.5%	9.5%	27.0%	35.0%	15.0%	4.0%
6	19.0%	19.0%	54.0%	0%	0%	7.9%
7	19.0%	19.0%	54.0%	0%	0%	7.9%
8	19.0%	19.0%	54.0%	0%	0%	7.9%
9	19.0%	19.0%	54.0%	0%	0%	7.9%
10	19.0%	19.0%	54.0%	0%	0%	7.9%
11	19.0%	19.0%	54.0%	0%	0%	7.9%
12	19.0%	19.0%	54.0%	0%	0%	7.9%
13	19.0%	19.0%	54.0%	0%	0%	7.9%

Source: DOE Contractors.

8.3.9 Effective Date of Standard

The effective date of the new energy-efficiency standards for distribution transformers is three years after the Department issues the final rule. The Department assumed that it will issue the final rule in 2004; therefore, the new standards will take effect in 2007. The Department calculated the LCC for all users as if each new distribution transformer purchase occurs in the year the standards take effect. It based the cost of the equipment on that year; however, as stated above, the Department expresses all dollar values in 2001 dollars.

8.3.10 Transformer Service Life

The Department defined distribution transformer service life as the age at which the transformer retires from service. The Department assumed, based on ORNL-6847, *Determination Analysis of Energy Conservation Standards for Distribution Transformers*,[10] that the average life of distribution transformers is 32 years. This lifetime assumption includes a constant failure rate of 0.5 percent/year due to lightning and other random failures unrelated to transformer age, and an additional corrosive failure rate of 0.5 percent/year at year 15 and beyond. The Department adjusted the retirement distribution to maintain an average life of 32 years.

8.3.11 Maintenance Costs

The maintenance cost is the cost to the consumer of maintaining equipment operation. The maintenance cost is not the cost associated with the replacement or repair of components that have failed. Rather, the maintenance cost is associated with general maintenance. The Department assumed that the cost for general maintenance will not change with increased efficiency. In practice, there is little scheduled maintenance for transformers. Maintenance consists of brief annual checks for dust buildup, vermin infestation, and accident or lightning damage.

8.3.12 Power Factor

The power factor is the real power divided by the apparent power. Real power is the time average of the instantaneous product of voltage and current. Apparent power is the product of the root mean square voltage times the root mean square current. When specifying transformer efficiency, specifications such as NEMA's TP 1-2002 (see the TP 1-2002 document paragraph 1.3) assume a power factor of 1.0. Thus, the Department used a power factor of 1.0, both in calculating the efficiency levels in the engineering analysis and when preparing candidate standard levels for the Advance Notice of Proposed Rulemaking (ANOPR).

However, in real-world installations, the loads experienced by distribution transformers are likely to have power factors of less than 1.0. Because the LCC analysis models transformers that are installed and operating in the field, DOE created the spreadsheet with an adjustable power factor, enabling the LCC to run at lower power factor values. In the absence of any specific data or guidance on the appropriate power factor, the Department used 1.0 for this LCC analysis.

8.3.13 Default Scenario

The Department developed distinct scenarios for several key input parameters. It described these distinct scenarios as low, medium, and high. For each of the key inputs, the Department chose the medium designation as the default scenario. The overall default scenario used in the LCC analysis has the following values:

- Transformer Load Growth/Year: Medium (=1 percent) for liquid-immersed, Low (=0 percent) for dry-type.
- Transformer Loading (relative to current estimate): Medium (=0 percent)
- Electricity Prices (relative to current estimate): Medium (=0 percent)
- Utility Decision As & Bs: Medium
- Future Energy Price Trend: *AEO 2003* Reference

The Department believes that these selections provide a good representation of current conditions. Other scenarios can be readily used to explore sensitivities to variations of these key variables.

8.4 LCC RESULTS

This section presents LCC results for the efficiency improvement levels evaluated for all 13 design lines. Table 8.4.1 provides an overview of the five candidate standard levels the Department evaluated for each of the 13 design lines examined. The lowest-efficiency candidate standard level is NEMA's TP 1-2002 and the highest is the most-efficient design identified in the engineering analysis. The remaining three efficiency levels are spread between these two bounds. The Department expresses all the candidate standard levels in terms of efficiency, with no explicit or implicit technology assumed. The Department based the results presented here on the inputs described in section 8.3.

Table 8.4.1 Candidate Standard Levels Evaluated For Each Design Line

Design Line	Level 1		Level 2		Level 3		Level 4		Level 5	
	TP 1+	Std. Lvl.	TP 1+	Std. Lvl.	TP 1+	Std. Lvl.	TP 1+	Std. Lvl.	TP 1+	Std. Lvl.
1	0.00%	98.90%	0.20%	99.10%	0.40%	99.30%	0.50%	99.40%	0.68%	99.58%
2	0.00%	98.70%	0.20%	98.90%	0.40%	99.10%	0.60%	99.30%	0.77%	99.47%
3	0.00%	99.30%	0.10%	99.40%	0.30%	99.60%	0.40%	99.70%	0.45%	99.75%
4	0.00%	98.90%	0.20%	99.10%	0.40%	99.30%	0.50%	99.40%	0.66%	99.56%
5	0.00%	99.30%	0.10%	99.40%	0.20%	99.50%	0.30%	99.60%	0.36%	99.66%
6	0.00%	98.00%	0.20%	98.20%	0.40%	98.40%	0.70%	98.70%	0.79%	98.79%
7	0.00%	98.00%	0.30%	98.30%	0.60%	98.60%	0.90%	98.90%	1.09%	99.09%
8	0.00%	98.60%	0.20%	98.80%	0.40%	99.00%	0.60%	99.20%	0.67%	99.27%
9	0.00%	98.60%	0.20%	98.80%	0.40%	99.00%	0.60%	99.20%	0.71%	99.31%
10	0.00%	99.10%	0.10%	99.20%	0.20%	99.30%	0.30%	99.40%	0.34%	99.44%
11	0.00%	98.50%	0.20%	98.70%	0.40%	98.90%	0.50%	99.00%	0.60%	99.10%
12	0.00%	99.00%	0.10%	99.10%	0.30%	99.30%	0.40%	99.40%	0.45%	99.45%
13	0.00%	99.00%	0.10%	99.10%	0.30%	99.30%	0.40%	99.40%	0.45%	99.45%

One of the primary impacts of an energy-efficiency standard is the change in the set of transformer designs available for purchase and their corresponding loss characteristics, load losses (LL), and no-load losses (NL). This impact is illustrated in the LL versus NL graph (fourth from right worksheet in the LCC spreadsheet). Figure 8.4.1 provides an illustration of the LL versus NL graph taken from the LCC spreadsheet for design line 9, using the TP 1-2002 standard level. Since each design line has a unique set of engineering constraints, the LL-versus-NL graph for each design will be different. This graph plots an example of a Crystal Ball® LCC run (limited to 50 iterations for legibility in this graphic format). It shows different sets of designs by their load losses at rated load and their no-load losses. Potential designs are shown as both small dots and small squares. The standard level is illustrated by a thick line (those designs that satisfy the standard are to the left of this line). The selected designs not subject to standard constraints are plotted as triangles. The designs subject to standards constraints are plotted as dots. As the standard level increases, the thick line moves parallel to the left (to the area of the graph with lower losses), and so does the set of constrained designs. The standard level is selected with the corresponding pull-down menu on the "Summary" sheet. Some of the selected designs (especially those with higher load losses) meeting the standard are plotted to the right of the line. This is because the efficiency rating and design assumptions use different-percentage loading definitions. The efficiency level is defined at 50 percent (liquid-immersed) or 35 percent (dry-type) loading, while the load and non-load losses are defined by nameplate loading (100 percent). For those designs with higher load losses, the heating from losses causes the actual efficiency to drop, shifting the design to the right.

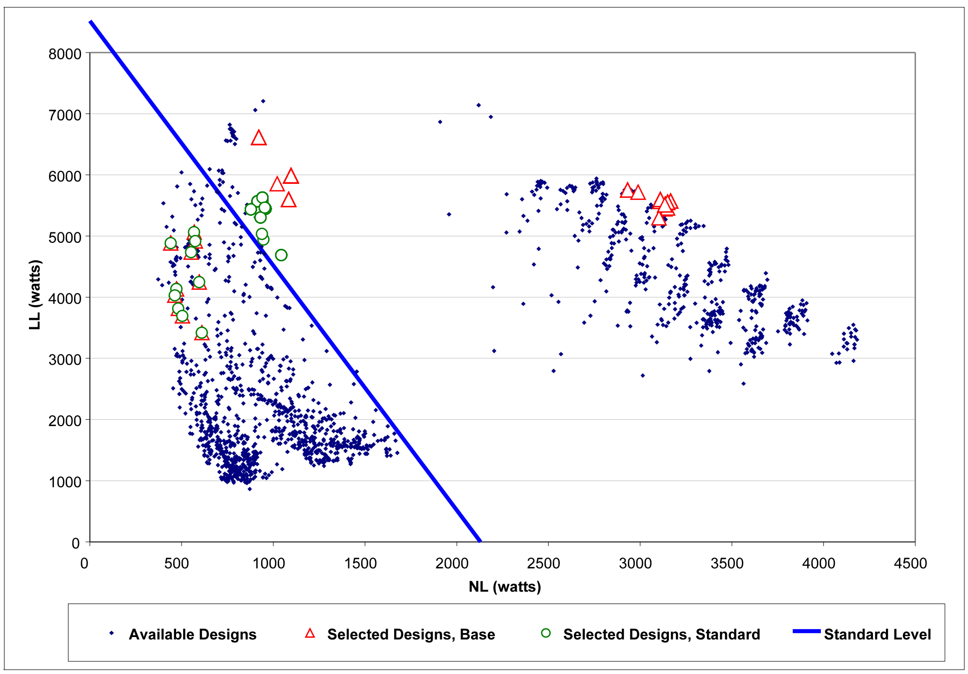

Figure 8.4.1 Design Load Losses (LL) versus No-load Losses (NL) for TP 1-2002, Design Line 9

The following 13 tables present the summary results from the Department's LCC analysis. For each evaluated design line and each candidate standard level, the Department presents the percent efficiency, the percent of evaluated transformer purchases that would experience positive LCC savings when subject to the candidate standard level, the mean LCC savings, and the minimum and maximum LCC savings. The Department presents these summary results for consideration; it has not selected any specific candidate standard level for any design line. Graphical representations of these results, which provide a clearer indication of the full distributions, are included in Appendix 8A.

8.4.1 Design Line 1 Results

Table 8.4.2 presents the summary of the LCC analysis for the representative unit from design line 1, a 50 kVA, liquid-immersed, single-phase, pad-mounted transformer. For this unit, the average efficiency of the baseline transformers selected during the LCC analysis was 98.91 percent and the average manufacturer's selling price was $1,580.00.

Table 8.4.2 Summary LCC Results for Design Line 1 Representative Unit

	Candidate Standard Level				
	1	2	3	4	5
Efficiency (%)	98.90	99.10	99.30	99.40	99.58
Transformers having LCC Savings ≥ $0 (%)	99.5	86.3	41.4	35.8	13.1
Mean LCC Savings ($)	134	158	-13	-64	-359

8.4.2 Design Line 2 Results

Table 8.4.3 presents the summary of the LCC analysis for the representative unit from design line 2, a 25 kVA, liquid-immersed, single-phase, pole-mounted transformer. For this unit, the average efficiency of the baseline transformers selected during the LCC analysis was 98.59 percent and the average manufacturer's selling price was $950.00.

Table 8.4.3 Summary LCC Results for Design Line 2 Representative Unit

	Candidate Standard Level				
	1	2	3	4	5
Efficiency (%)	98.70	98.90	99.10	99.30	99.47
Transformers having LCC Savings ≥ $0 (%)	99.7	66.7	26.8	13.7	2.8
Mean LCC Savings ($)	99	62	-76	-216	-492

8.4.3 Design Line 3 Results

Table 8.44 presents the summary of the LCC analysis for the representative unit from design line 3, a 500 kVA, liquid-immersed, single-phase distribution transformer. For this unit, the average efficiency of the baseline transformers selected during the LCC analysis was 99.33 percent and the average manufacturer's selling price was $4,599.00.

Table 8.4.4 Summary LCC Results for Design Line 3 Representative Unit

	Candidate Standard Level				
	1	2	3	4	5
Efficiency (%)	99.30	99.40	99.60	99.70	99.75
Transformers having LCC Savings ≥ $0 (%)	96.5	97.5	70.3	68.9	52.1
Mean LCC Savings ($)	884	1,606	1,168	1,838	1,292

8.4.4 Design Line 4 Results

Table 8.4.55 presents the summary of the LCC analysis for the representative unit from design line 4, a 150 kVA, liquid-immersed, three-phase distribution transformer. For this unit, the average efficiency of the baseline transformers selected during the LCC analysis was 98.86 percent and the average manufacturer's selling price was $3,577.00.

Table 8.4.5 Summary LCC Results for Design Line 4 Representative Unit

	Candidate Standard Level				
	1	2	3	4	5
Efficiency (%)	98.90	99.10	99.30	99.40	99.56
Transformers having LCC Savings ≥ $0 (%)	97.5	90.9	73.7	75.9	50.8
Mean LCC Savings ($)	574	733	491	585	301

8.4.5 Design Line 5 Results

Table 8.4.6 presents the summary of the LCC analysis for the representative unit from design line 5, a 1500 kVA, liquid-immersed, three-phase distribution transformer. For this unit, the average efficiency of the baseline transformers selected during the LCC analysis was 99.35 percent and the average manufacturer's selling price was $11,088.00.

Table 8.4.6 Summary LCC Results for Design Line 5 Representative Unit

	Candidate Standard Level				
	1	2	3	4	5
Efficiency (%)	99.30	99.40	99.50	99.60	99.66
Transformers having LCC Savings ≥ $0 (%)	97.8	97.2	80.2	78.5	64.4
Mean LCC Savings ($)	4,174	6,617	7,451	7,268	6,838

8.4.6 Design Line 6 Results

Table 8.4.7 presents the summary of the LCC analysis for the representative unit from design line 6, a 25 kVA, low-voltage, dry-type, single-phase transformer. For this unit, the average efficiency of the baseline transformers selected during the LCC analysis was 95.36 percent and the average manufacturer's selling price was $864.00.

Table 8.4.7 Summary LCC Results for Design Line 6 Representative Unit

	Candidate Standard Level				
	1	2	3	4	5
Efficiency (%)	98.00	98.20	98.40	98.70	98.79
Transformers having LCC Savings ≥ $0 (%)	99.3	99.1	99.1	94.1	92.8
Mean LCC Savings ($)	1,777	1,865	1,948	1,906	1,867

8.4.7 Design Line 7 Results

Table 8.4.8 presents the summary of the LCC analysis for the representative unit from design line 7, a 75 kVA, low-voltage, dry-type, three-phase transformer. For this unit, the average efficiency of the baseline transformers selected during the LCC analysis was 96.43 percent and the average manufacturer's selling price was $1,808.00.

Table 8.4.8 Summary LCC Results for Design Line 7 Representative Unit

	Candidate Standard Level				
	1	2	3	4	5
Efficiency (%)	98.00	98.30	98.60	98.90	99.09
Transformers having LCC Savings ≥ $0 (%)	100.0	99.0	98.4	88.8	77.5
Mean LCC Savings ($)	3,156	3,588	3,927	3,910	3,799

8.4.8 Design Line 8 Results

Table 8.4.9 presents the summary of the LCC analysis for the representative unit from design line 8, a 300 kVA, low-voltage, dry-type, single-phase transformer. For this unit, the average efficiency of the baseline transformers selected during the LCC analysis was 97.79 percent and the average manufacturer's selling price was $4,735.00.

Table 8.4.9 Summary LCC Results for Design Line 8 Representative Unit

	Candidate Standard Level				
	1	2	3	4	5
Efficiency (%)	98.60	98.80	99.00	99.20	99.27
Transformers having LCC Savings ≥ $0 (%)	99.8	97.8	96.6	92.1	89.4
Mean LCC Savings ($)	6,761	7,035	7,899	8,941	8,712

8.4.9 Design Line 9 Results

Table 8.4.10 presents the summary of the LCC analysis for the representative unit from design line 9, a 300 kVA, medium-voltage, dry-type, three-phase transformer with a 45kV basic impulse insulation level (BIL). For this unit, the average efficiency of the baseline transformers selected during the LCC analysis was 97.90 percent and the average manufacturer's selling price was $6,084.00.

Table 8.4.10 Summary LCC Results for Design Line 9 Representative Unit

	Candidate Standard Level				
	1	2	3	4	5
Efficiency (%)	98.60	98.80	99.00	99.20	99.31
Transformers having LCC Savings ≥ $0 (%)	95.8	93.4	95.2	84.6	70.0
Mean LCC Savings ($)	6,465	7,550	8,536	8,942	7,838

8.4.10 Design Line 10 Results

Table 8.4.11 presents the summary of the LCC analysis for the representative unit from design line 10, a 1500 kVA, medium-voltage, dry-type, three-phase transformer with a 45kV BIL. For this unit, the average efficiency of the baseline transformers selected during the LCC analysis was 98.63 percent and the average manufacturer's selling price was $22,473.00.

Table 8.4.11 Summary LCC Results for Design Line 10 Representative Unit

	Candidate Standard Level				
	1	2	3	4	5
Efficiency (%)	99.10	99.20	99.30	99.40	99.44
Transformers having LCC Savings ≥ $0 (%)	89.9	90.5	90.0	72.1	64.5
Mean LCC Savings ($)	14,458	16,130	18,050	15,594	13,704

8.4.11 Design Line 11 Results

Table 8.4.12 presents the summary of the LCC analysis for the representative unit from design line 11, a 300 kVA, medium-voltage, dry-type, three-phase transformer with a 95kV BIL. For this unit, the average efficiency of the baseline transformers selected during the LCC analysis was 97.77 percent and the average manufacturer’s selling price was $10,142.00.

Table 8.4.12 Summary LCC Results for Design Line 11 Representative Unit

	Candidate Standard Level				
	1	2	3	4	5
Efficiency (%)	98.50	98.70	98.90	99.00	99.10
Transformers having LCC Savings ≥ $0 (%)	96.4	94.9	87.4	75.6	68.0
Mean LCC Savings ($)	4,473	5,350	5,734	5,136	4,666

8.4.12 Design Line 12 Results

Table 8.4.13 presents the summary of the LCC analysis for the representative unit from design line 12, a 1500 kVA, medium-voltage, dry-type, three-phase transformer with a 95kV BIL. For this unit, the average efficiency of the baseline transformers selected during the LCC analysis was 98.67 percent and the average manufacturer’s selling price was $26,542.00.

Table 8.4.13 Summary LCC Results for Design Line 12 Representative Unit

	Candidate Standard Level				
	1	2	3	4	5
Efficiency (%)	99.00	99.10	99.30	99.40	99.45
Transformers having LCC Savings ≥ $0 (%)	91.5	85.8	84.6	71.0	59.6
Mean LCC Savings ($)	8,369	12,318	15,390	14,365	11,341

8.4.13 Design Line 13 Results

Table 8.4.14 presents the summary of the LCC analysis for the representative unit from design line 13, a 2000 kVA, medium-voltage, dry-type, three-phase transformer with a 125kV BIL. For this unit, the average efficiency of the baseline transformers selected during the LCC analysis was 98.73 percent and the average manufacturer’s selling price was $37,082.00.

Table 8.4.14 Summary LCC Savings for Design Line 13 Representative Unit

	Candidate Standard Level				
	1	**2**	**3**	**4**	**5**
Efficiency (%)	99.00	99.10	99.30	99.40	99.45
Transformers having LCC Savings ≥ $0 (%)	92.0	90.6	76.9	77.6	44.9
Mean LCC Savings ($)	11,691	16,119	16,685	19,706	7,593

8.5 LCC SENSITIVITY ANALYSIS

The Department recognizes that there is always some uncertainty associated with engineering and economic analyses. To minimize that uncertainty, the Department strives to use the best techniques and the best data at its disposal. To cover the widest possible set of scenarios in this analysis, the Department used distributions of values for key inputs. For some variables, the Department went one step further by including in the analysis tool the ability to repeat the very same LCC analysis using values different from the default set used to produce the Department's results.

Detailed descriptions of all of the LCC input variables are included in the discussion of inputs in section 8.3, with additional information in Chapters 6 and 7. This section focuses on four key variables and the impact on the LCC results of assigning them a range of different values. The four variables and the location of their descriptive materials are as follows:

1. Percentage of transformers purchased using A&B evaluation (see section 8.3.1);

2. Transformer loading (see Chapter 6);

3. Electricity price trends (see section 8.3.7); and

4. Load growth trends (see section 8.3.6).

This sensitivity analysis examines how sensitive the results are to changes in key DOE assumptions. For the ANOPR, DOE conducted the sensitivity analysis on design lines 1 and 9, the "representative" liquid-immersed and dry-type transformers that it used in the development of the LCC. Based on stakeholder feedback, these sensitivity analyses may be expanded in the notice of proposed rulemaking (NOPR). This analysis treats each variable independently, i.e., default values remain in effect for all variables except the one being examined. Sensitivity results should always be compared to the default results. Each of the four variables have three values—low, medium, and high—that are described in more detail in the individual input variable sections.

The variable that characterizes the percentage of transformers purchased using A and B evaluation uses the same set of low and high values for both liquid-immersed and dry-type transformers. The low value represents a scenario where no transformer purchases are evaluated, i.e., a non-evaluating scenario. The high value represents a scenario where all transformer purchases are evaluated. The medium value for dry-type transformers represents a scenario where 10 percent of purchases are evaluated. The medium value for liquid-immersed represents a scenario where 50 percent of the purchases are evaluated.

For transformer loading, the medium scenario represents the output of the load simulation described in Chapter 6. The low scenario decreases the medium scenario load by 15 percent and the high scenario increases the medium scenario by 15 percent. For load growth, the low, medium, and high annual scenarios are zero percent, one percent, and two percent, respectively. Electricity price trends use the *AEO 2003* low, reference, and high growth scenarios.

8.5.1 Design Line 1 Summary Sensitivity Results

The representative unit from design line 1 is a 50 kVA, liquid-immersed, single-phase, pad-mounted transformer. For this unit, the average efficiency of the baseline transformers selected during the LCC analysis was 98.91 percent and the average manufacturer's selling price was $1,580.00. Table 8.5.1 and Figures 8.5.1 through 8.5.6 illustrate the LCC sensitivity to changes in the four user-selectable variables. Each of the sensitivity runs for all the variables causes some change in the LCC results. However, for design line 1, only the change in percentage of transformers purchased using A & B evaluation results in significant changes in the results for all levels examined. Figures 8.5.2-8.5.6 provide the clearest example of this. The Department found that the variable labeled A & B distribution stands significantly apart from the other variables for most candidate standard levels. The reason that the A & B distribution is so important is that it describes whether or not the transformer purchasers will buy efficient transformers even without a standard. If transformer purchasers already buy efficient transformers, then standards will not change purchase behavior much, and the impact of a candidate standard level will be small. A standard can even have the adverse consequence of forcing a purchaser to buy a transformer that is more efficient than needed. If no purchasers buy efficient transformers without a standard, then a standard can have a large beneficial impact from decreased energy costs. The A & B Distribution options describe the full range of possible purchase behavior scenarios.

The next biggest impact is from the projection of future electricity prices which, at the higher levels of efficiency, shows significant LCC impacts. For the ranges examined, the Department found that changing transformer loading and load growth assumptions do not result in significant changes in LCC results.

Table 8.5.1 Mean LCC Savings ($), Summary for Design Line 1 Representative Unit

Scenario	Candidate Standard Level				
	1	2	3	4	5
Baseline	134	158	-13	-64	-359
Non Evaluating A & B Distribution	254	309	134	75	-223
High Evaluating A & B Distribution	9	14	-159	-201	-488
Low Loading	129	142	-35	-80	-397
High Loading	138	177	16	-45	-307
Low Electricity Price	114	126	-69	-144	-448
High Electricity Price	150	196	44	13	-263
Low Load Growth	127	146	-41	-88	-406
High Load Growth	132	168	-2	-55	-328

8.5.2 Design Line 1 Sensitivity Results by Candidate Standard Level

In Figure 8.5.2, the large sensitivity to A and B evaluation percentage is obvious in the upper and lower plots that stand apart from the other values. Similarly, the low sensitivity to electricity price and load growth can be seen in their small difference from the default medium scenario. Figures 8.5.2 through 8.5.6 plot the sensitivities for each candidate level individually. Again, the A and B evaluation percentage stand out with much more sensitivity than the other variables. Figure 8.5.2 also illustrates the decline in LCC savings for all scenarios with candidate standard level (CSL) higher than CSL 2.

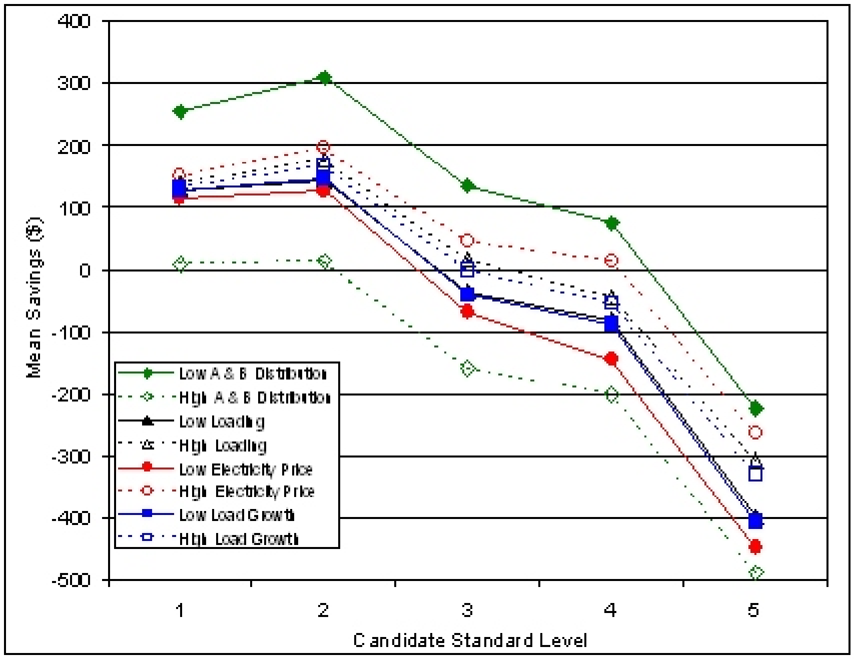

Figure 8.5.1 Mean LCC Savings ($), Summary Sensitivity Scenarios for Design Line 1

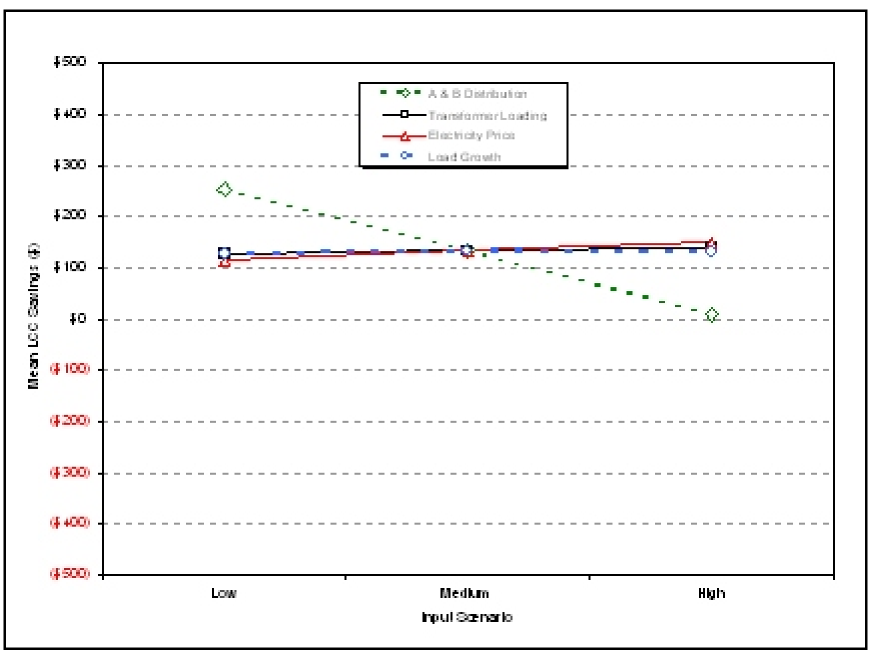

Figure 8.5.2 Sensitivity of LCC to Input Changes for Design Line 1, Candidate Standard Level 1

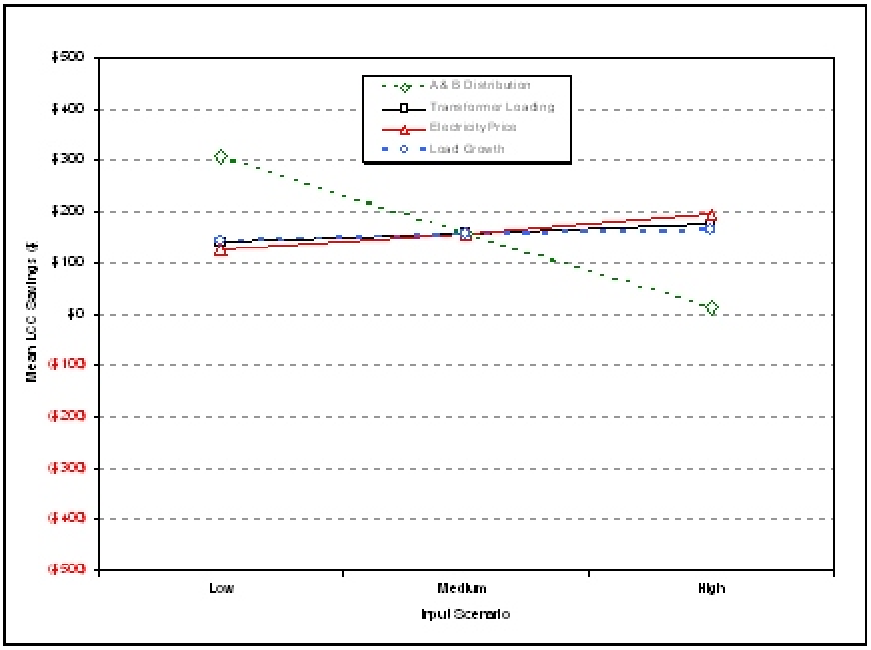

Figure 8.5.3 Sensitivity of LCC to Input Changes for Design Line 1, Candidate Standard Level 2

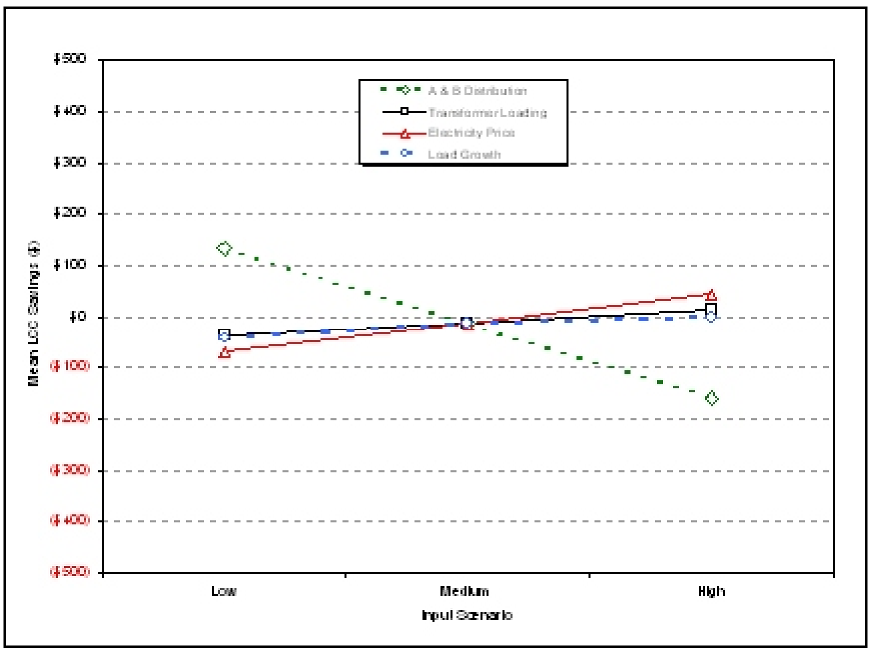

Figure 8.5.4 Sensitivity of LCC to Input Changes for Design Line 1, Candidate Standard Level 3

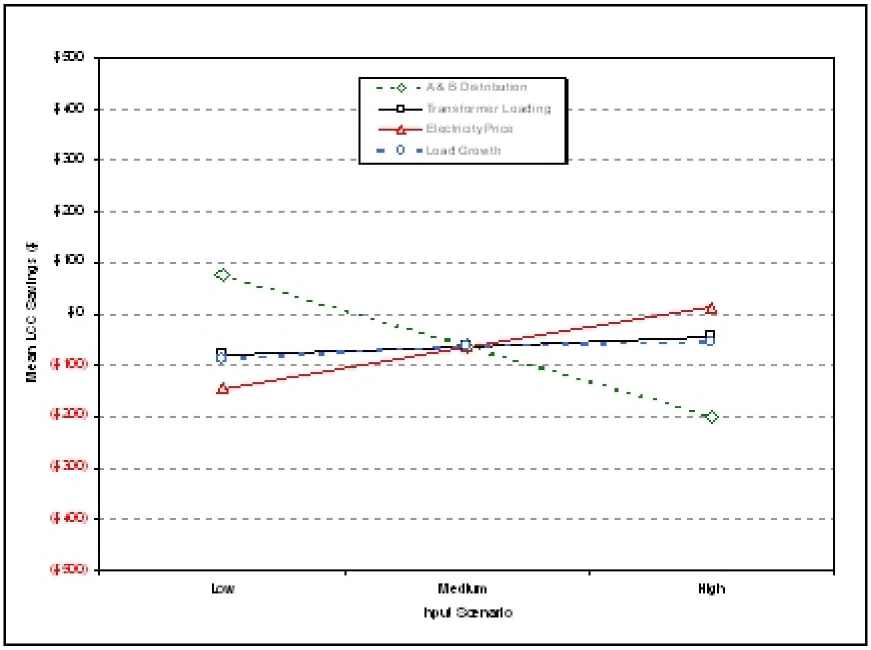

Figure 8.5.5 Sensitivity of LCC to Input Changes for Design Line 1, Candidate Standard Level 4

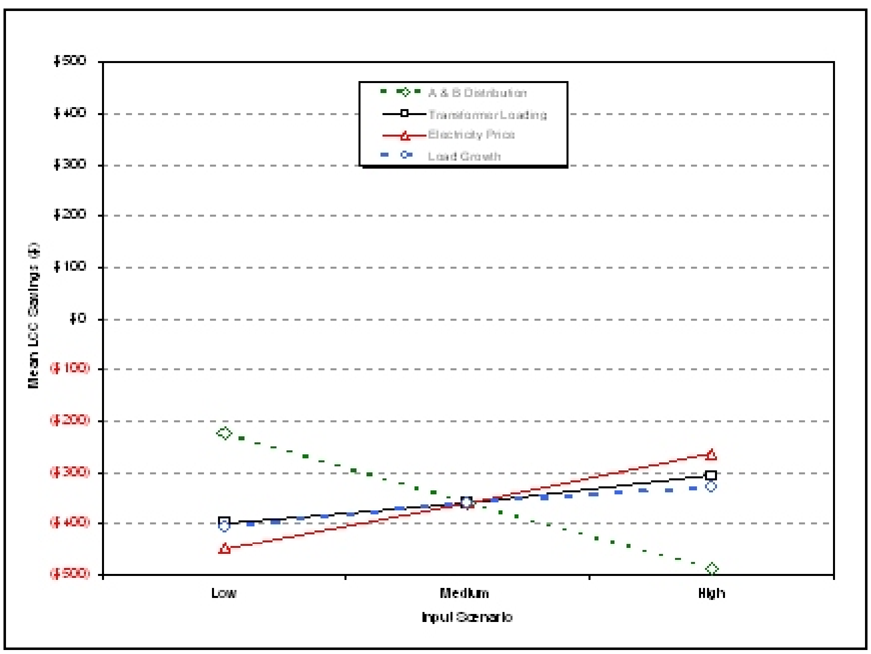

Figure 8.5.6 Sensitivity of LCC to Input Changes for Design Line 1, Candidate Standard Level 5

8.5.3 Design Line 9 Summary Sensitivity Results

The representative unit from design line 9 is a 300 kVA, medium-voltage, dry-type, three-phase transformer with a 45kV BIL. For this unit, the average efficiency of the baseline transformers selected during the LCC analysis was 97.90 percent and the average manufacturer's selling price was $6,084.00. Table 8.5.2 and Figures 8.5.7-8.5.12 illustrate the LCC sensitivity to changes in the four user-selectable variables for design line 9. Each of the sensitivity runs for all the variables causes some change in the LCC results. The changes in results tend to increase with the efficiency of the candidate standard level. For design line 9, the change in percentage of transformers purchased using A & B evaluation results in significantly larger changes in the results, for all levels examined, than do the other variables. Figures 8.5.8-8.5.12 provide the clearest example of this. As with design line 1, this is because the purchase behavior described by A & B strongly affects how much energy is used when there is no standard, and thus affects the potential savings. The extremely low savings from the High A & B distribution case results from the fact that the Department assumes that most purchasers buy efficient transformers in that scenario even without standards. For most candidate standard levels, the variable labeled *A & B Distribution* stands significantly apart from the other variables.

The next most significant impact is from the projection of future electricity prices, which shows significant LCC impact for all levels examined. For the ranges examined, the Department found that changing transformer loading and load growth assumptions results in significant changes in LCC results only at the higher efficiency levels.

Table 8.5.2 Mean LCC Savings ($), Summary for Design Line 9 Representative Unit

Scenario	Candidate Standard Level				
	1	2	3	4	5
Baseline	6,648	7,572	9,109	9,664	8,954
Non Evaluating A & B Distribution	7,442	8,632	10,016	10,709	9,842
High Evaluating A & B Distribution	113	395	682	1,150	379
Low Loading	6,689	7,762	8,686	9,182	8,279
High Loading	6,623	7,963	9,433	10,466	10,189
Low Electricity Price	5,578	6,353	7,375	7,872	6,770
High Electricity Price	7,671	8,984	10,746	11,763	11,110
Low Load Growth	6,465	7,550	8,536	8,942	7,838
High Load Growth	6,762	7,817	9,166	9,902	9,454

8.5.4 Design Line 9 Sensitivity Results by Candidate Standard Level

In Figure 8.5.7, the large sensitivity to high A and B evaluation percentage is obvious in the lower plot that stands apart from the other values. Similarly, the low sensitivity to electricity price and load growth can be seen in their small difference from the default medium scenario. Figures 8.5.8 through 8.5.12 plot the sensitivities for each candidate level individually. Again, the high A and B evaluation percentage stands out with much more sensitivity than the other variables. The percentage of purchasers conducting A- and B-based evaluations in the high scenario for this dry-type design line is 100 percent compared to the default medium scenario of 10 percent conducting evaluations, so the difference is quite large and a significant difference in results should be expected. In Figure 8.5.7, the increase in mean LCC savings up to CSL 4 and then a drop-off at CSL 5 can be seen.

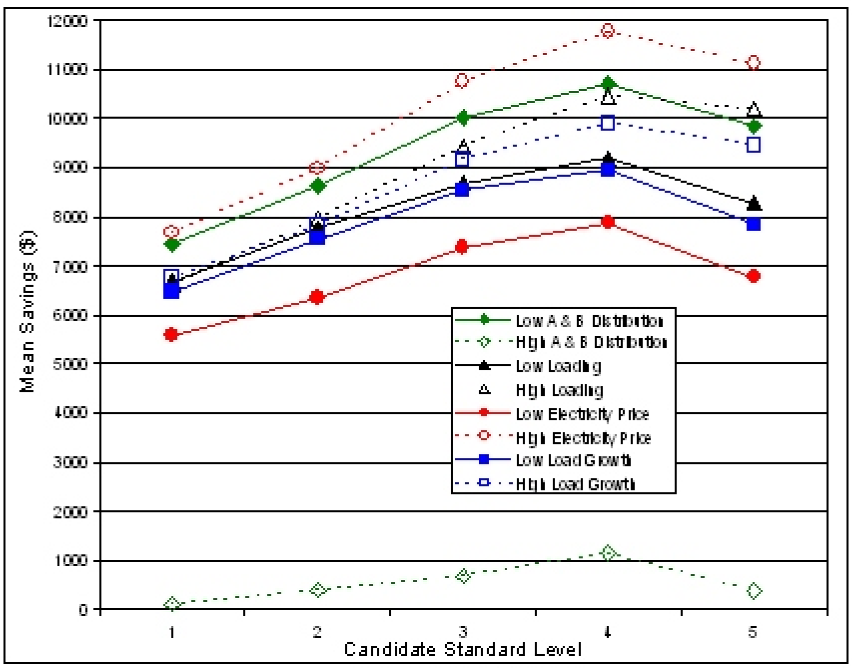

Figure 8.5.7 Mean LCC Savings ($), Summary Sensitivity Scenarios for Design Line 9

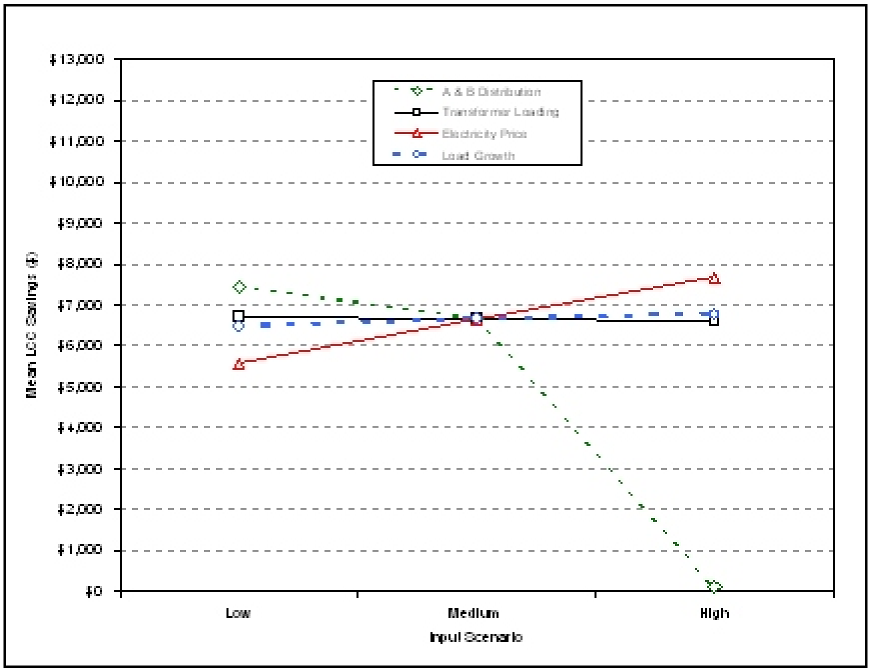

Figure 8.5.8 Sensitivity of LCC to Input Changes for Design Line 9, Candidate Standard Level 1

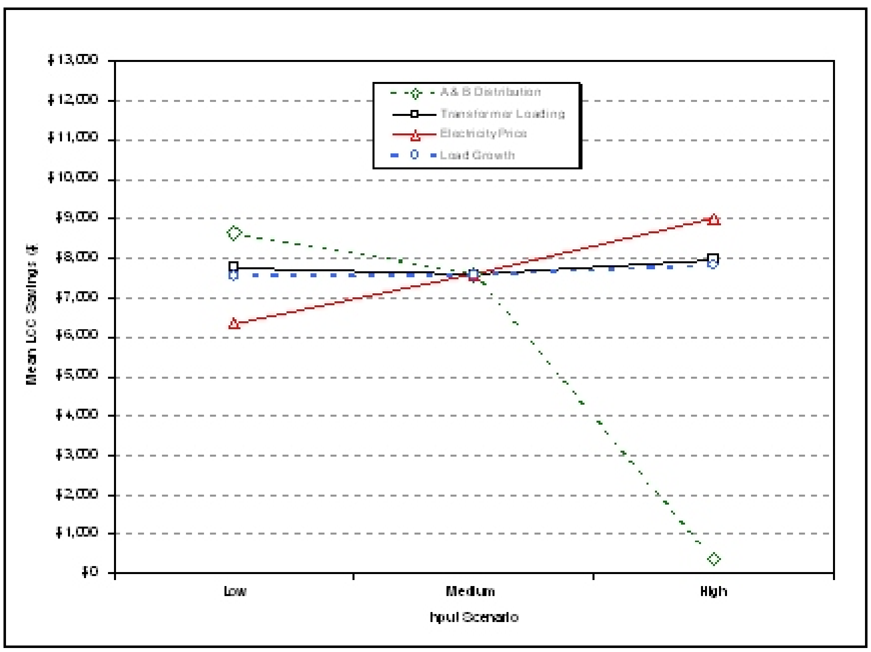

Figure 8.5.9 Sensitivity of LCC to Input Changes for Design Line 9, Candidate Standard Level 2

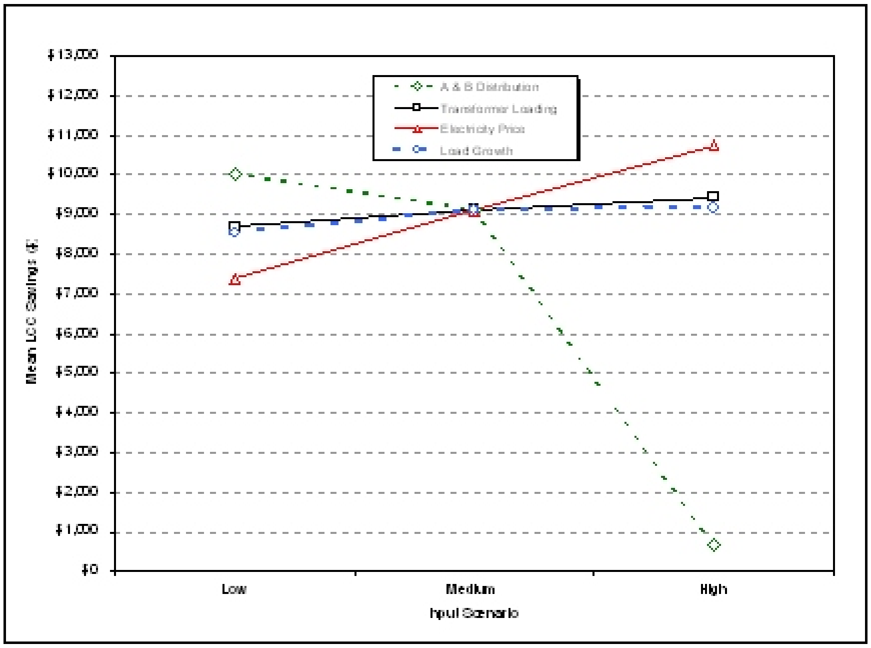

Figure 8.5.10 Sensitivity of LCC to Input Changes for Design Line 9, Candidate Standard Level 3

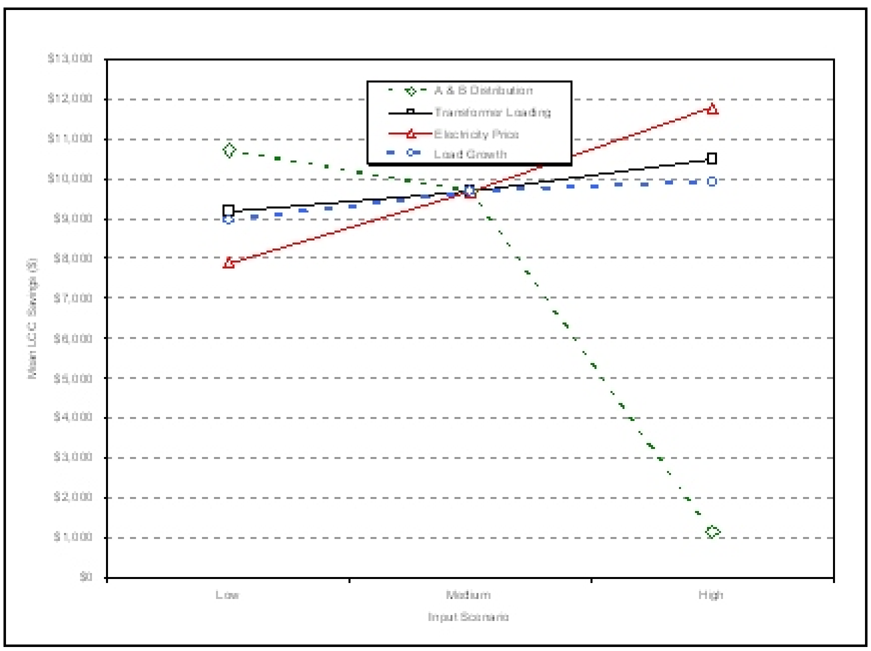

Figure 8.5.11 Sensitivity of LCC to Input Changes for Design Line 9, Candidate Standard Level 4

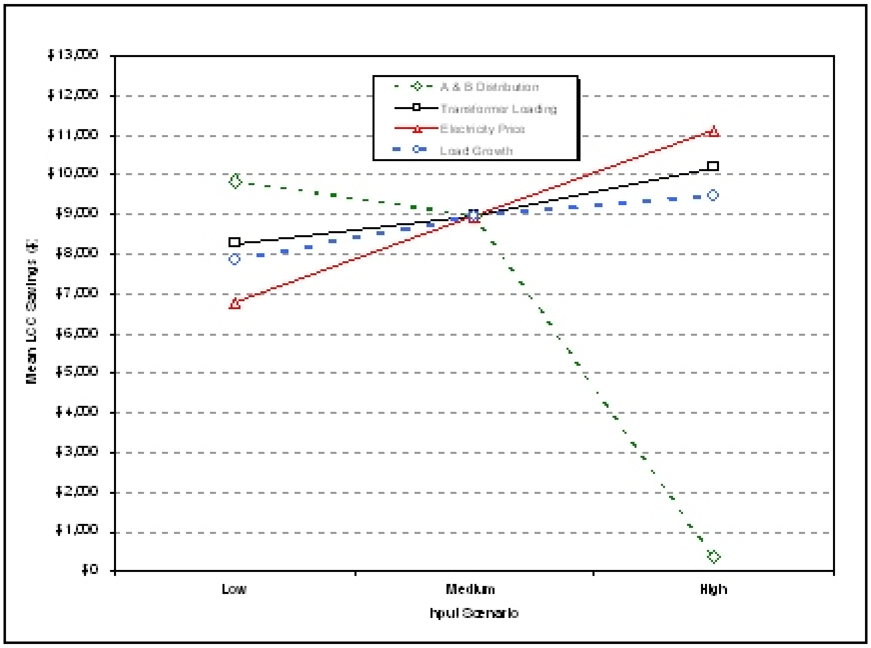

Figure 8.5.12 Sensitivity of LCC to Input Changes for Design Line 9, Candidate Standard Level 5

8.6 DISTRIBUTIONAL PAYBACK PERIOD

A common technique used to evaluate investment decisions is PBP analysis. A more energy-efficient device will usually cost more to purchase than a device of standard energy efficiency. However, the more efficient device will usually cost less to operate, due to the reduction in energy use. The payback period is the time (usually expressed in years) it takes to recover the additional first cost of the efficient device with its energy cost savings. Because the LCC analysis uses distributions of inputs, DOE gives results such as payback periods in the form of distributions.

8.6.1 Payback Period

The PBP measures the time it takes the consumer to recover the assumed higher purchase expense (i.e., higher first cost) of more energy-efficient equipment through lower operating costs. Numerically, the PBP is the ratio of the increase in purchase expense (i.e., from a less-efficient design to a more-efficient design) to the decrease in annual operating expenditures. This type of calculation is known as a "simple" payback period, because is does not take into account changes in operating expense over time or the time value of money; i.e., the calculation is done at an effective discount rate of zero percent.

Payback period is found using the equation:

$$PBP = \frac{\Delta FC}{\Delta OC} \qquad \textbf{Eq. 8.8}$$

where:

$\Delta FC =$ installed purchase price ("first cost") of a transformer satisfying the candidate standard level minus the installed purchase price ("first cost") of a transformer in the absence of the standard (assumes the transformer meeting the standard is more expensive than the transformer not subject to the standard); and

$\Delta OC =$ operating cost of the transformer not subject to the standard minus the operating cost of the transformer subject to the standard (assumes the transformer meeting the candidate standard level has lower energy consumption, and hence lower operating cost, than the transformer not subject to the standard). Because ΔOC is expressed in annual terms, PBP is expressed in years.

8.6.2 Inputs

The inputs to PBP are: 1) the purchase expense, otherwise known as the total installed consumer cost, or "first cost," for each selected design, and 2) the annual (first year) operating expenditures for each selected design. The inputs to the purchase expense are the equipment price and the installation cost with appropriate markups. The inputs to the operating costs are the annual energy consumption and the electricity price. The distribution PBP uses the same inputs as the LCC analysis described in section 8.3, with a few exceptions described below.

Since this is a "simple" payback, the electricity price used is only for the year the standard takes effect, assumed here to be 2007. The Department did not use discount rates for the payback calculation.

8.6.3 Baseline Scenario Complications

Since distribution transformers are not currently subject to energy-efficiency standards, the Department developed the baseline scenario method to estimate transformer purchase behavior in the current market. The Department's default assumptions for the baseline scenario were that some portion of transformer purchase decisions are based on TOC-type evaluations. Specifically, those default assumptions for use of TOC-type evaluation are 50 percent for liquid-immersed transformers and 10 percent for dry-type transformers, both using a distribution of A and B evaluation factors. Especially at the lower candidate standard levels evaluated by the Department, the transformer purchases based on TOC may not satisfy the basic PBP assumptions of higher purchase price and lower operating costs for the transformers subject to the candidate standard. When these basic assumptions are not satisfied, the traditional PBP calculation loses its validity.

For example, a current transformer purchase decision based on TOC may have identical first cost ($\Delta FC = 0$) as a transformer just meeting TP 1. In addition, the transformer meeting the standard may have a different operating cost than the transformer purchased without the standard. In such a situation, the transformer purchase decision is not affected by the standard and PBP = 0. In another example, a current transformer purchase decision based on TOC may result in a transformer costing more to purchase and install and consuming less electricity than a transformer that just meets TP 1. In this case, the PBP calculation for the standard is nonsensical, since it would imply a negative payback period. The possible cases are shown in Table 8.6.1.

Table 8.6.1 Possible Cases of First Cost (FC) and Operating Cost (OC) Combinations, for PBP Analysis

Possible Cases	Value of PBP	Interpretation of PBP Value
[FC (baseline) < FC (standard)] and [OC (baseline) > OC (standard)]	PBP > 0	Valid payback period.
[FC (baseline) = FC (standard)] and [OC (baseline) ≠OC (standard)]	PBP = 0	Valid, but purchase decision not likely to be affected by standard. Standard only potentially helpful if: OC (baseline) > OC (standard).
[FC (baseline) < FC (standard)] and [OC (baseline) < OC (standard)]	PBP < 0	Not valid: Negative payback.
[FC (baseline) > FC (standard)] and [OC (baseline) > OC (standard)]	PBP < 0	Not valid: Negative payback.
[FC (standard) ≤or> FC (baseline)] and [OC (baseline) = OC (standard)]	PBP is undefined	Not valid: Division by zero.

8.6.4 PBP Results

Tables 8.6.2 through 8.6.14 illustrate, for all 13 design lines and the five candidate standard levels, the mean PBP and the percentage of the 10,000 Monte Carlo simulations where the PBP calculation applies. For each candidate standard level for each design line, the sum of the two percentages from the tables and the percentage where the PBP calculation applies should equal 100 percent. As the efficiency of the candidate standard levels increases, the percentage of purchase decisions where the PBP assumptions are satisfied increases. A complete set of PBP histograms for all cases presented in these tables is included in Appendix 8A.

8.6.5 Design Line 1 Results

Table 8.6.2 presents the summary of the PBP analysis for the representative unit from design line 1, a 50 kVA, liquid-immersed, single-phase, pad-mounted transformer. For this unit, the average efficiency of the baseline transformers selected during the LCC analysis was 98.91 percent and the average manufacturer's selling price was $1,580.00.

Table 8.6.2 Summary of Payback Period Results for Design Line 1 Representative Unit

	Candidate Standard Level				
	1	**2**	**3**	**4**	**5**
Mean Payback (Years)	6.3	14.5	25.1	23.3	32.5
Transformers having Well Defined Payback (%)	39.8	68.5	96.0	95.9	99.1
Transformers having No Impact on Payback (%)	56.3	30.6	0.0	0.0	0.0
Transformers having Undefined Payback (%)	3.9	0.9	4.0	4.1	0.9
Mean Incremental First Cost ($)	122	206	588	872	1,262
Mean Operating Cost Savings ($)	22	22	30	43	46

8.6.6 Design Line 2 Results

Table 8.6.3 presents the summary of the PBP analysis for the representative unit from design line 2, a 25 kVA, liquid-immersed, single-phase, pole-mounted transformer. For this unit, the average efficiency of the baseline transformers selected during the LCC analysis was 98.59 percent and the average manufacturer's selling price was $950.00.

Table 8.6.3 Summary of Payback Period Results for Design Line 2 Representative Unit

	Candidate Standard Level				
	1	**2**	**3**	**4**	**5**
Mean Payback (Years)	5.8	21.7	30.3	29.7	40.7
Transformers having Well Defined Payback (%)	37.0	83.1	98.9	99.1	99.6
Transformers having No Impact on Payback (%)	55.7	16.6	0.0	0.0	0.0
Transformers having Undefined Payback (%)	7.3	0.2	1.1	1.0	0.4
Mean Incremental First Cost ($)	79	172	410	747	1,074
Mean Operating Cost Savings ($)	15	13	18	28	30

8.6.7 Design Line 3 Results

Table 8.6.4 presents the summary of the PBP analysis for the representative unit from design line 3, a 500 kVA, liquid-immersed, single-phase distribution transformer. For this unit, the average efficiency of the baseline transformers selected during the LCC analysis was 99.33 percent and the average manufacturer's selling price was $4,599.00.

Table 8.6.4 Summary of Payback Period Results for Design Line 3 Representative Unit

	Candidate Standard Level				
	1	**2**	**3**	**4**	**5**
Mean Payback (Years)	8.2	8.3	16.9	18.1	23.6
Transformers having Well Defined Payback (%)	55.7	63.8	87.9	93.8	97.0
Transformers having No Impact on Payback (%)	43.9	36.0	12.1	0.0	0.0
Transformers having Undefined Payback (%)	0.4	0.2	0.0	6.2	3.0
Mean Incremental First Cost ($)	647	1,145	3,956	4,877	6,926
Mean Operating Cost Savings ($)	106	174	270	332	388

8.6.8 Design Line 4 Results

Table 8.6.5 presents the summary of the PBP analysis for the representative unit from design line 4, a 150 kVA, liquid-immersed, three-phase distribution transformer. For this unit, the average efficiency of the baseline transformers selected during the LCC analysis was 98.86 percent and the average manufacturer's selling price was $3,577.00.

Table 8.6.5 Summary of Payback Period Results for Design Line 4 Representative Unit

	Candidate Standard Level				
	1	**2**	**3**	**4**	**5**
Mean Payback (Years)	7.7	12.1	16.5	16.2	24.7
Transformers having Well Defined Payback (%)	57.6	75.4	83.4	84.2	95.7
Transformers having No Impact on Payback (%)	42.1	24.2	16.7	15.8	0.0
Transformers having Undefined Payback (%)	0.3	0.5	0.0	0.0	4.3
Mean Incremental First Cost ($)	452	788	2,081	2,120	2,882
Mean Operating Cost Savings ($)	75	90	142	148	159

8.6.9 Design Line 5 Results

Table 8.6.6 presents the summary of the PBP analyses for the representative unit from design line 5, a 1500 kVA, liquid-immersed, three-phase distribution transformer. For this unit, the average efficiency of the baseline transformers selected during the LCC analysis was 99.35 perent and the average manufacturer's selling price was $11,088.00.

Table 8.6.6 Summary of Payback Period Results for Design Line 5 Representative Unit

	Candidate Standard Level				
	1	**2**	**3**	**4**	**5**
Mean Payback (Years)	6.2	6.7	13.4	13.4	17.7
Transformers having Well Defined Payback (%)	58.0	67.1	86.2	91.2	97.2
Transformers having No Impact on Payback (%)	41.5	32.3	13.5	8.8	0.0
Transformers having Undefined Payback (%)	0.5	0.6	0.3	0.0	2.9
Mean Incremental First Cost ($)	1,445	2,849	6,598	9,497	13,163
Mean Operating Cost Savings ($)	415	625	757	917	1,037

8.6.10 Design Line 6 Results

Table 8.6.7 presents the summary of the PBP analysis for the representative unit from design line 6, a 25 kVA, low-voltage, dry-type, single-phase transformer. For this unit, the average efficiency of the baseline transformers selected during the LCC analysis was 95.36 percent and the average manufacturer's selling price was $864.00.

Table 8.6.7 Summary of Payback Period Results for Design Line 6 Representative Unit

	Candidate Standard Level				
	1	**2**	**3**	**4**	**5**
Mean Payback (Years)	1.7	2.6	2.6	5.6	6.7
Transformers having Well Defined Payback (%)	92.5	93.3	93.3	99.0	99.3
Transformers having No Impact on Payback (%)	7.4	6.7	6.6	0.6	0.4
Transformers having Undefined Payback (%)	0.1	0.0	0.1	0.4	0.4
Mean Incremental First Cost ($)	158	272	272	468	596
Mean Operating Cost Savings ($)	137	150	156	159	163

8.6.11 Design Line 7 Results

Table 8.6.8 presents the summary of the PBP analysis for the representative unit from design line 7, a 75 kVA, low-voltage, dry-type, three-phase transformer. For this unit, the average efficiency of the baseline transformers selected during the LCC analysis was 96.43 percent and the average manufacturer's selling price was $1,808.00.

Table 8.6.8 Summary of Payback Period Results for Design Line 7 Representative Unit

	Candidate Standard Level				
	1	2	3	4	5
Mean Payback (Years)	0.6	2.6	3.5	7.1	10.8
Transformers having Well Defined Payback (%)	47.6	89.3	92.2	98.2	100.0
Transformers having No Impact on Payback (%)	40.9	9.7	7.8	1.5	0.0
Transformers having Undefined Payback (%)	11.5	1.0	0.0	0.3	0.0
Mean Incremental First Cost ($)	153	230	449	932	1,783
Mean Operating Cost Savings ($)	398	280	312	325	367

8.6.12 Design Line 8 Results

Table 8.6.9 presents the summary of the PBP analyses for the representative unit from design line 8, a 300 kVA, low-voltage, dry-type, single-phase transformer. For this unit, the average efficiency of the baseline transformers selected during the LCC analysis was 97.79 percent and the average manufacturer's selling price was $4,735.00.

Table 8.6.9 Summary of Payback Period Results for Design Line 8 Representative Unit

	Candidate Standard Level				
	1	2	3	4	5
Mean Payback (Years)	1.0	2.9	4.5	6.5	7.4
Transformers having Well Defined Payback (%)	66.8	90.2	92.4	97.8	99.5
Transformers having No Impact on Payback (%)	26.3	9.7	7.6	1.8	0.3
Transformers having Undefined Payback (%)	6.9	0.1	0.0	0.5	0.2
Mean Incremental First Cost ($)	338	463	1,293	2,201	2,765
Mean Operating Cost Savings ($)	635	548	652	750	764

8.6.13 Design Line 9 Results

Table 8.6.10 presents the summary of the PBP analysis for the representative unit from design line 9, a 300 kVA, medium-voltage, dry-type, three-phase transformer with a 45kV BIL. For this unit, the average efficiency of the baseline transformers selected during the LCC analysis was 97.90 percent and the average manufacturer's selling price was $6,084.00.

Table 8.6.10 Summary of Payback Period Results for Design Line 9 Representative Unit

	Candidate Standard Level				
	1	2	3	4	5
Mean Payback (Years)	4.8	6.1	5.7	8.9	13.1
Transformers having Well Defined Payback (%)	90.4	91.9	94.5	97.8	99.9
Transformers having No Impact on Payback (%)	9.3	8.0	5.4	2.0	0.0
Transformers having Undefined Payback (%)	0.3	0.1	0.1	0.2	0.0
Mean Incremental First Cost ($)	411	1,220	1,795	3,443	5,346
Mean Operating Cost Savings ($)	501	629	722	830	876

8.6.14 Design Line 10 Results

Table 8.6.11 presents the summary of the PBP analysis for the representative unit from design line 10, a 1500 kVA, medium-voltage, dry-type, three-phase transformer with a 45kV BIL. For this unit, the average efficiency of the baseline transformers selected during the LCC analysis was 98.63 percent and the average manufacturer’s selling price was $22,473.00.

Table 8.6.11 Summary of Payback Period Results for Design Line 10 Representative Unit

	Candidate Standard Level				
	1	2	3	4	5
Mean Payback (Years)	8.5	8.5	8.9	13.9	15.6
Transformers having Well Defined Payback (%)	93.8	95.0	96.1	99.3	99.9
Transformers having No Impact on Payback (%)	5.8	4.9	3.8	0.5	0.0
Transformers having Undefined Payback (%)	0.4	0.1	0.1	0.2	0.1
Mean Incremental First Cost ($)	6,513	7,622	10,462	17,000	20,807
Mean Operating Cost Savings ($)	1,443	1,619	1,941	2,165	2,275

8.6.15 Design Line 11 Results

Table 8.6.12 presents the summary of the PBP analysis for the representative unit from design line 11, a 300 kVA, medium-voltage, dry-type, three-phase transformer with a 95kV BIL. For this unit, the average efficiency of the baseline transformers selected during the LCC analysis was 97.77 percent and the average manufacturer’s selling price was $10,142.

Table 8.6.12 Summary of Payback Period Results for Design Line 11 Representative Unit

	Candidate Standard Level				
	1	**2**	**3**	**4**	**5**
Mean Payback (Years)	5.8	6.7	9.3	12.5	14.3
Transformers having Well Defined Payback (%)	92.5	94.4	97.0	98.7	99.9
Transformers having No Impact on Payback (%)	7.4	5.6	2.7	1.2	0.0
Transformers having Undefined Payback (%)	0.1	0.1	0.3	0.1	0.0
Mean Incremental First Cost ($)	1,579	2,248	3,569	5,226	6,571
Mean Operating Cost Savings ($)	425	526	628	688	745

8.6.16 Design Line 12 Results

Table 8.6.13 presents the summary of the PBP analysis for the representative unit from design line 12, a 1500 kVA, medium-voltage, dry-type, three-phase transformer with a 95kV BIL. For this unit, the average efficiency of the baseline transformers selected during the LCC analysis was 98.67 percent and the average manufacturer's selling price was $26,542.00.

Table 8.6.13 Summary of Payback Period Results for Design Line 12 Representative Unit

	Candidate Standard Level				
	1	**2**	**3**	**4**	**5**
Mean Payback (Years)	8.0	9.6	10.7	14.2	17.1
Transformers having Well Defined Payback (%)	91.4	92.4	97.2	99.3	100.0
Transformers having No Impact on Payback (%)	8.6	6.0	2.7	0.5	0.0
Transformers having Undefined Payback (%)	0.0	1.6	0.0	0.2	0.0
Mean Incremental First Cost ($)	3,966	5,850	10,961	16,577	21,951
Mean Operating Cost Savings ($)	873	1,273	1,772	2,060	2,185

8.6.17 Design Line 13 Results

Table 8.6.14 presents the summary of the PBP analysis for the representative unit from design line 13, a 2000 kVA, medium-voltage, dry-type, three-phase transformer with a 125kV BIL. For this unit, the average efficiency of the baseline transformers selected during the LCC analysis was 98.73 percent and the average manufacturer's selling price was $37,082.00.

Table 8.6.14 Summary of Payback Period Results for Design Line 13 Representative Unit

	Candidate Standard Level				
	1	2	3	4	5
Mean Payback (Years)	6.7	8.5	12.7	12.7	20.3
Transformers having Well Defined Payback (%)	90.6	93.7	97.1	99.1	99.9
Transformers having No Impact on Payback (%)	9.1	6.1	2.9	0.7	0.0
Transformers having Undefined Payback (%)	0.3	0.2	0.1	0.3	0.1
Mean Incremental First Cost ($)	3,372	7,730	17,013	19,611	35,192
Mean Operating Cost Savings ($)	1,070	1,648	2,252	2,596	2,825

8.7 USER INSTRUCTIONS FOR SPREADSHEETS

To execute the LCC spreadsheet, it is necessary for the user to have the appropriate hardware and software tools. The Department assumed the user has a reasonably current computer operating under the Windows® operating system. The development team uses relatively new systems and has not defined the minimum system requirements. At a minimum, all users need Microsoft Excel® to execute the spreadsheet. For full functionality in running Monte Carlo simulations, users will need a copy of a spreadsheet add-in called Crystal Ball®, in addition to Excel®. Without Crystal Ball®, one can still use the LCC spreadsheet model, but cannot use or examine inputs and outputs as distributions. Approximate results are provided through a sample calculation that uses average values for the inputs and outputs, as displayed in the “Summary” worksheet.

8.7.1 Startup

The LCC spreadsheet file is a stored Excel® file. Open the file. (Each computer system will have a unique setup for loading a file. Users should refer to their software manuals if they have problems loading the spreadsheet file.) For users new to Excel® and/or Crystal Ball®, basic instructions for operating the LCC spreadsheets are covered in section 8.7.2.

8.7.1.1 Sheet Overview

Each of the five liquid-immersed LCC spreadsheets contain the following 17 worksheets.

- Options
- Description
- Summary
- A & B Distribution

- Design Table
- Load and Price Parameters
- Utilities
- Discount Rate
- Hourly Loads
- Hourly Prices
- Annual Energy Price Forecast
- Baseline LCC
- Design Option LCC
- Lifetime
- Load-Price Charts
- Results - LLvNL
- LL vs NL

Each of the eight dry-type LCC spreadsheets contain the following 17 worksheets.

- Description
- Summary
- A & B Distribution
- Design Table
- Demand and Usage
- Utilities
- Discount Rate
- Annual Energy Price Forecast
- Baseline LCC
- Design Option LCC
- Lifetime
- Load-Price Charts
- Results - LLvNL
- LL vs NL
- Tariffs
- Components
- Options

Most of the worksheets consist of the data inputs used in the spreadsheet calculations. For functionality in the spreadsheet model while maintaining reasonable size, DOE pre-processed some variables into a representative equation. "Hourly Loads" and "Hourly Prices" are the two best examples of using an equation (Fourier transform) to express a complex set of data in an equation. "Load - Price Charts" provides a graphical expression of the "Hourly Loads" and "Hourly Prices."

The spreadsheet/user interface is centered in the Summary worksheet. Changing user-selectable options will produce average results shown on the Summary, i.e., results using the mean inputs. From the very nature of Monte Carlo mathematics, the average results will not be identical to the distribution mean produced from Monte Carlo Crystal Ball® simulations, but will provide quick feedback reflecting nominal results to spreadsheet users. The Department conducted an example Monte Carlo run of 100 iterations to produce "Results - LLvNL" which is shown graphically as "LL vs NL." Selecting different standard levels in the "Summary" worksheet will produce a different graphical result on the "LL vs NL" sheet, as well as different average results on the "Summary" worksheet.

8.7.2 Basic Instructions for Operating the LCC Spreadsheets

1. Once you have downloaded the LCC file from the Web, open the file using Excel®. At the bottom, click on the tab for sheet "Summary."

2. Use Excel's "View/Zoom" commands at the top menu bar to change the size of the display to make it fit your monitor.

3. The user interacts with the spreadsheet by clicking choices or entering data using the graphical interface that comes with the spreadsheet. Select choices from the various inputs listed under the "User Options" heading. You can also enter a new discount rate or lifetime if you want to use a value other than the default value or default distribution; however, this changes the code. As a result, the Department does not recommend saving the spreadsheet after the code is changed.

4. To change inputs listed under "User Options," select the input you wish to change by either clicking on the appropriate button or selecting the appropriate input from the input box.

To produce sensitivity results using Crystal Ball®, select *Run* from the Run menu (on the menu bar). To make basic changes in the run sequence, including altering the number of trials, select *Run Preferences* from the Run menu. After each simulation run, the user needs to select *Reset* (also from the Run menu) before *Run* can be selected again. Once Crystal Ball® has completed its run sequence, it will produce a series of distributions. Using the menu bars on the distribution results, it is possible to obtain further statistical information. The time taken to complete a run sequence can be reduced by minimizing the Crystal Ball® window in Excel®. A step-by-step summary of the procedure for running a distribution analysis is outlined below:

1. Find the Crystal Ball® toolbar (at top of screen).
2. Click on Run from the menu bar.
3. Select *Run Preferences* and choose from the following choices:
    a. Monte Carlo[a]

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[a] Because of the nature of the program, there is some variation in results due to random sampling when Monte Carlo or Latin Hypercube sampling is used.

b. Latin Hypercube (recommended)
c. Select number of Monte Carlo Trials (the Department suggests 10,000).

4. To run the simulation, follow the following sequence (on the Crystal Ball® toolbar)
Run
Reset
Run

5. Now wait until the program informs you that the simulation is completed.

The Department provides the following instructions to view the output generated by Crystal Ball®:

1. After the simulation has finished, click on the Windows® tab bar labeled Crystal Ball® to see the distribution charts.

2. The LCC savings and PBPs are defined as *Forecast* cells. The frequency charts display the results of the simulations, or trials, performed by Crystal Ball®. Click on any chart to bring it into view. The charts show the low and high endpoints of the forecasts. The *View* selection on the Crystal Ball® toolbar can be used to specify whether cumulative or frequency plots are to be shown.

3. To calculate the probability that a particular value of LCC savings will occur, either type 0 in the box by the left arrow, or move the arrow key with the cursor to 0 on the scale. The value in the *Certainty* box shows the likelihood that the LCC savings will occur. To calculate the certainty of the payback period being below a certain number of years, choose that value as the high dpoint.

4. To generate a printout report, select *Create Report* from the Run menu. The toolbar choice of *Forecast Windows* allows you to select the charts and statistics in which you are interested. For further information on Crystal Ball® outputs, refer to *Understanding the Forecast Chart* in the Crystal Ball® manual.

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